NUREG-1786

Safety Evaluation Report
Related to the License Renewal of R.E. Ginna Nuclear Power Plant

Docket No. 50-244

Rochester Gas & Electric Corporation

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

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February 2004

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ABSTRACT

This safety evaluation report (SER) documents the technical review of the R.E. Ginna Nuclear Power Plant (Ginna) license renewal application (LRA) by the U.S. Nuclear Regulatory Commission staff (staff). By letter dated July 30, 2002, Rochester Gas & Electric Corporation (RG&E or the applicant) submitted the LRA for Ginna in accordance with Title 10, Part 54, of the *Code of Federal Regulations* (10 CFR Part 54 or the Rule). Through that LRA, RG&E requested that the U.S. Nuclear Regulatory Commission (NRC) renew the operating license for Ginna (license number DPR-18) for a period of 20 years beyond the current expiration of midnight, September 18, 2009.

The Ginna plant is located in the Town of Ontario, in the northwest corner of Wayne County, New York, on the south shore of Lake Ontario. The NRC issued the construction permit in April 1966, followed by a provisional operating license on September 19, 1969, and a full-term operating license on December 10, 1984. The Ginna unit consists of a Westinghouse pressurized-water reactor with nuclear steam supply systems designed to operate at core power levels up to 1,520 megawatts-thermal, or approximately 490 megawatts-electric.

This SER presents the status of the staff's review of information submitted to the NRC through January 9, 2004. In its SER with open items, issued on October 9, 2003, the staff identified open and confirmatory items that required resolution before the staff could make a final determination on the application. These items are summarized in Sections 1.5 and 1.6 of this report. The staff's final conclusion of its review of the Ginna LRA can be found in Section 6 of this SER.

The NRC Ginna license renewal project manager is Mr. Russell J. Arrighi. Mr. Arrighi may be reached at 301-415-3936. Written correspondence should be addressed to the License Renewal and Environmental Impacts Program, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001.

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ABBREVIATIONS

A	ampacity
ac	alternating current
ABVS	auxiliary building ventilation system
ACI	American Concrete Institute
ACRS	Advisory Committee on Reactor Safeguards (NRC)
AEC	Atomic Energy Commission, U.S.
AFW	auxiliary feedwater
AISC	American Institute of Steel Construction
AISI	American Iron and Steel Institute
AMP	aging management program
AMR	aging management review
AMSAC	ATWS mitigating system actuation circuitry
ANS	American Nuclear Society
ANSI	American National Standards Institute
ARV	atmospheric relief valve
ASM	American Society for Metals
AR	action request
ASME	American Society of Mechanical Engineers
ASNT	American Society for Nondestructive Testing
ASTM	American Society for Testing and Materials
ATWS	anticipated transient without scram
AVT	all-volatile treatment
AWS	American Welding Society
BMI	bottom-mounted instrument
BTP	branch technical position
B&W	Babcock and Wilcox Co.
BWR	boiling-water reactor
C	Celsius
CAR	corrective action report
CASS	cast austenitic stainless steel
CCW	component cooling water
CHDR	containment hydrogen detectors and recombiner
CE	Combustion Engineering
cfm	cubic feet per minute
CFR	*Code of Federal Regulations*
CIC	contaminant isolation component
CLB	current licensing basis
CMIS	Configuration Management Information System
C-RAI	clarification of request for additional information
CRD	control rod drive
CRDM	control rod drive mechanism
CREATS	control room emergency air treatment system
CS	containment spray
CST	condensate storage tank

CUF	cumulative usage factor
CVCS	chemical and volume control system
CW	circulating water
DAM	data acquisition modules
DBD	design-basis document
dc	direct current
D-RAI	draft request for additional information
ECCS	emergency core cooling system
EDG	emergency diesel generator
EDY	effective degradation years
EFPY	effective full-power year
EPRI	Electric Power Research Institute
EQ	environmental qualification
ESF	engineered safety features
F	Fahrenheit
FAC	flow-accelerated corrosion
F_{en}	environmental fatigue multiplier
FERC	Federal Energy Regulatory Commission
FOSAR	foreign object surveys and retrieval
FP	fire protection
FRP	fiberglass-reinforced plastic
FSAR	final safety analysis report
ft-lb	foot-pound
GAI	Gilbert Associates, Inc.
GALL	Generic Aging Lessons Learned (Report)
GEIS	generic environmental impact statement
GL	generic letter
gpm	gallons per minute
GSI	generic safety issue
GTR	generic technical report
HELB	high-energy line break
HEPA	high-efficiency particulate air
HTK	high-temperature kerite
HVAC	heating, ventilation, and air conditioning
I&C	instrumentation and controls
IASCC	irradiation-assisted stress-corrosion cracking
ID	inner diameter
IDR	inspection discrepancy report
IEB	inspection and enforcement bulletin
IGA	intergranular attack
IGSCC	intergranular stress-corrosion cracking

IN	information notice
INPO	Institute of Nuclear Power Operations
IPA	integrated plant assessment
IR	insulation resistance
ISG	interim staff guidance
ISI	inservice inspection
J	joule
ksi	thousand pounds per square inch
kV	kilovolt
LBB	leak before break
LER	licensee event report
LOCA	loss-of-coolant accident
LR	license renewal
LRA	license renewal application
M	margin
MeV	1 million electron volts
MIC	microbiologically influenced corrosion
MOV	motor-operated valve
MRP	Materials Reliability Program
MRV	minimum required value
MSIV	main steam isolation valve
msl	mean sea level
MSSV	main steam safety valve
MT	magnetic particle test
n/cm^2	neutrons per squared centimeter
NACE	National Association of Corrosion Engineers
NCR	nonconformance report
NDE	nondestructive examination
ND-QAP	Quality Assurance Program for Station Operation
NEI	Nuclear Energy Institute
NEPA	National Environmental Policy Act
NFPA	National Fire Protection Association
NNS	nonnuclear safety
NPAR	nuclear plant aging research
NPS	nominal pipe size
NRC	U.S. Nuclear Regulatory Commission
NSAC	Nuclear Safety Analysis Center
NSSS	nuclear steam supply system

OD	outside diameter
ODSCC	outer-diameter stress-corrosion cracking
OPPD	Omaha Public Power District
OPT	operability test
P&ID	piping and instrumentation diagram
PLL	predicted lower limit
PMT	post maintenance testing
PORV	power-operated relief valve
ppm	parts per million
psi	pounds per square inch
P/T	pressure and temperature
PTS	pressurized thermal shock
PVC	polyvinyl chloride
PWR	pressurized-water reactor
PWSCC	primary water stress-corrosion cracking
QA	quality assurance
QAPSO	Quality Assurance Program for Station Operator
RAI	request for additional information
RCCA	rod cluster control assembly
RCP	reactor coolant pump
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
rem	roentgen equivalent man
RG	regulatory guide
RG&E	Rochester Gas & Electric Corporation
RHR	residual heat removal
RPV	reactor pressure vessel
RT	radiography testing
RTD	resistance temperature detector
RT_{PTS}	reference temperature for pressurized thermal shock
RT_{NDT}	reference temperature nil ductility
RV	reactor vessel
RVI	reactor vessel internals
RVID	Reactor Vessel Integrity Database
RWST	refueling water storage tank
Sa	stress intensity
SAFW	standby auxiliary feedwater
SBO	station blackout
SC	structure and component
SC-1	safety class 1
SC-2	safety class 2
SC-3	safety class 3

SCC	stress-corrosion cracking
SE	safety evaluation
SEP	Systematic Evaluation Program
SER	safety evaluation report
SFP	spent fuel pool
SFC&FS	spent fuel cooling and fuel storage
SFR	system function report
SG	steam generator
SI	safety injection
SIT	structural integrity test
SOC	Statements of Consideration
SOER	significant operating event report
SPCS	steam and power conversion systems
SRP	Standard Review Plan
SRP-LR	standard review plan—license renewal
SS	safety significant
SSC	structure, system, and component
SW	service water
TDAFW	turbine-driven auxiliary feedwater
TEDE	total effective dose equivalent
TLAA	time-limited aging analysis
TR	topical report
TRM	technical requirements manual
TS	technical specification
TSC	technical support center
TSR	technical specification surveillance requirement
UFSAR	updated final safety analysis report
USAS	United States of America Standards
USE	upper-shelf energy
UT	ultrasonic testing
UV	ultraviolet
V	volt
VT	visual test
WCAP	Westinghouse Commercial Atomic Power
WOG	Westinghouse Owners Group

1. INTRODUCTION AND GENERAL DISCUSSION

1.1 Introduction

This document is a safety evaluation report (SER) on the application to renew the operating license for the R.E. Ginna Nuclear Power Plant (Ginna) as filed by Rochester Gas & Electric Corporation (RG&E or the applicant). By letter dated July 30, 2002, RG&E submitted its application asking the U.S. Nuclear Regulatory Commission (NRC or the agency) to renew the Ginna operating licenses for up to an additional 20 years. The NRC received the application on August 1, 2002. The NRC staff (the staff) reviewed the Ginna license renewal application (LRA) for compliance with the requirements of Title 10 of the *Code of Federal Regulations* (CFR), Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," and prepared this report to document the results of its safety review. The NRC license renewal project manager for the Ginna safety review is Russell J. Arrighi. Mr. Arrighi may be contacted by telephone at (301)415-3936 or by electronic mail at rja1@nrc.gov. Alternatively, written correspondence can be sent to the following address:

License Renewal and Environmental Impacts Program
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Attention: Russell J. Arrighi, Mail Stop O-11F1

In its submittal letter dated July 30, 2002, the applicant requested renewal of the operating license issued under Section 104b of the Atomic Energy Act of 1954, as amended, for Ginna (License No. DRP-18) for a period of 20 years beyond the current license expiration of midnight, September 18, 2009. The Ginna plant is located in the Town of Ontario, in the northwest corner of Wayne County, New York, on the south shore of Lake Ontario. The Ginna unit consists of a Westinghouse pressurized-water reactor (PWR) with nuclear steam supply systems (NSSSs) designed to operate at core power levels up to 1,520 megawatts-thermal, or approximately 490 megawatts-electric. Details concerning the plant and the site are found in the updated final safety analysis report (UFSAR) for Ginna.

The license renewal process proceeds along two tracks, which include both a technical review of safety issues and an environmental review. The requirements for these two reviews are stated in NRC regulations 10 CFR Parts 54 and 51, respectively. The safety review for the Ginna license renewal is based on the applicant's LRA, docket correspondences, and the answers to requests for additional information (RAIs) from the NRC staff. In meetings and docketed correspondence, the applicant has also supplemented its answers to the RAIs. Unless otherwise noted, the staff reviewed and considered information submitted through January 9, 2004. The public can review the LRA and all pertinent information and material, including the UFSAR, at the NRC Public Document Room, 11555 Rockville Pike, Rockville, Maryland 20852-2738. In addition, the Ginna LRA and significant information and material related to the license renewal review are available on the NRC's Web page at www.nrc.gov.

This SER summarizes the findings of the staff's safety review of the Ginna LRA and delineates the scope of the technical details considered in evaluating the safety aspects of the proposed operation of the plant for up to an additional 20 years beyond the term of the current operating license. The staff reviewed the LRA in accordance with NRC regulations and the guidance presented in the NRC "Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants" (SRP-LR), which the NRC issued as NUREG-1800 in July 2001.

Sections 2 through 4 of this SER document the staff's review and evaluation of license renewal issues that have been considered during the review of the LRA. Section 5 is reserved for the report of the Advisory Committee on Reactor Safeguards (ACRS). Section 6 presents the conclusions of this report.

Appendix A contains a list of commitments made by RG&E in association with the operating license renewal. Appendix B contains a chronology of the principal correspondence between the NRC and the applicant related to the review of the LRA. Appendix C lists the principal NRC staff's reviewers and contractors for this project. Appendix D lists the major references used in support of this SER.

In accordance with 10 CFR Part 51, the staff prepared a plant-specific supplement to the generic environmental impact statement (GEIS). This supplement discusses the environmental considerations related to renewing the license for Ginna. The staff issued the plant-specific supplement as Supplement 14 to NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding the R.E. Ginna Nuclear Power Plant," on February 6, 2004.

1.2 License Renewal Background

Pursuant to the Atomic Energy Act of 1954, as amended, and NRC regulations, licenses for commercial power reactors to operate are issued for up to 40 years. These licenses can be renewed for up to 20 additional years. The original 40-year license term was selected on the basis of economic and antitrust considerations, rather than on technical limitations. However, some individual plant and equipment designs may have been engineered on the basis of an expected 40-year service life.

In 1982, the NRC anticipated interest in license renewal and held a workshop on nuclear power plant aging. That led the NRC to establish a comprehensive program plan for nuclear plant aging research (NPAR). On the basis of the results of that research, a technical review group concluded that many aging phenomena are readily manageable and do not pose technical issues that would preclude extending the life of nuclear power plants. In 1986, the NRC published a request for comment on a policy statement that would address major policy, technical, and procedural issues related to license renewal for nuclear power plants.

In 1991, the NRC published the license renewal rule in 10 CFR Part 54 (the Rule). The NRC participated in an industry-sponsored demonstration program to apply the Rule to a pilot plant and develop experience to create implementation guidance. To establish a scope of review for license renewal, the rule defined age-related degradation unique to license renewal. However, during the demonstration program, the NRC found that many aging mechanisms occur and are managed during the period of the initial license. In addition, the NRC found that the scope of the review did not allow sufficient credit for existing aging management programs (AMPs), particularly for the implementation of the maintenance rule, 10 CFR 50.65, which also manages plant aging phenomena.

As a result, in 1995, the NRC amended 10 CFR Part 54. The amended License Renewal Rule establishes a regulatory process that is simpler, more stable, and more predictable than the previous license renewal rule. In particular, 10 CFR Part 54 was amended to focus on managing the adverse effects of aging rather than on identifying age-related degradation unique to license renewal. The Rule changes were intended to ensure that important structures, systems, and components (SSCs) within the scope of the Rule will continue to perform their intended functions in the period of extended operation. In addition, the integrated plant assessment (IPA) process was clarified and simplified to be consistent with the revised focus on passive, long-lived structures and components (SCs).

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

1.2.1 Safety Reviews

License renewal requirements for power reactors are based on two principles:

(1) The regulatory process is adequate to ensure that the licensing bases of all currently operating plants provide and maintain an acceptable level of safety, with the possible exception of the detrimental effects of aging on the functionality of certain SSCs during the period of extended operation, as well as a few other potential issues related to safety during the period of extended operation.

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

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

Pursuant to 10 CFR 54.21(a), the applicant for a renewed license must review all SSCs that are within the scope of the Rule to identify SCs that are subject to an aging management review (AMR). SCs that are subject to an AMR are those that perform an intended function without moving parts, or without a change in configuration or properties, and that are not subject to replacement based on a qualified life or specified time period. As required by 10 CFR 54.21(a)(3), an applicant for a renewed license must demonstrate that the effects of aging will be managed in such a way that the intended function or functions of the SCs that are within the scope of license renewal will be maintained, consistent with the current licensing basis (CLB), for the period of extended operation. Active equipment, however, is considered to be adequately monitored and maintained by existing programs. In other words, the detrimental effects of aging that may affect active equipment are more readily detectable and will be identified and corrected through routine surveillance, performance monitoring, and maintenance activities. The surveillance and maintenance programs for active equipment, as well as other aspects of maintaining the plant design and licensing basis, are required to continue throughout the period of extended operation.

Pursuant to 10 CFR 54.21(d), the LRA is required to include a supplement to the UFSAR. This UFSAR Supplement must contain a summary description of the applicant's programs and activities for managing the effects of aging.

Another requirement for license renewal is the identification and updating of time-limited aging analyses (TLAAs). During the design phase for a plant, certain assumptions are made about the initial length of time the plant will be operated and these assumptions are incorporated into design calculations for several of the plant's SSCs. In accordance with 10 CFR 54.21(c)(1), these calculations must be shown to be valid for the period of extended operation or must be projected to the end of the period of extended operation, or the applicant must demonstrate that the effects of aging on these SSCs will be adequately managed for the period of extended operation.

In July 2001, the NRC issued Regulatory Guide (RG) 1.188, "Standard Format and Content for Applications to Renew Nuclear Power Plant Operating License," NUREG-1800, "Standard Review Plan for the Review of License Renewal Application for Nuclear Power Plants (SRP-LR)," and NUREG-1801, "Generic Aging Lessons Learned (GALL) Report." These documents describe methods acceptable to the NRC staff for implementing the license renewal rule and techniques used by the NRC staff in evaluating applications for license renewal. The RG endorses an implementation guideline prepared by the Nuclear Energy Institute (NEI) as an acceptable method of implementing the license renewal rule. The NEI guideline, NEI 95-10, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54—The License Renewal Rule," Revision 3, was issued in March 2001.

RG&E is the third license renewal applicant to fully utilize the process defined in NUREG-1801, GALL Report, dated July 2001. The purpose of GALL is to provide the staff with a summary of staff-approved aging management programs (AMPs) for the aging of most SCs that are subject to an AMR. If an applicant commits to implementing these staff-approved AMPs, 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. The GALL Report summarizes the aging management evaluations, programs, and activities credited for managing aging for most of the SCs used throughout the industry, and serves as a reference for both applicants and staff reviewers to quickly identify those AMPs and activities that the staff has determined will provide adequate aging management during the period of extended operation.

1.2.2 Environmental Reviews

In December 1996, the staff revised the environmental protection regulations in 10 CFR Part 51 to facilitate environmental reviews for license renewal. The staff prepared a “Generic Environmental Impact Statement (GEIS) for License Renewal of Nuclear Plants” (NUREG-1437, Revision 1) to document its evaluation of the possible environmental impacts associated with renewing licenses of nuclear power plants. For certain types of environmental impacts, the GEIS establishes generic findings that are applicable to all nuclear power plants. These generic findings are identified as Category 1 issues in 10 CFR Part 51, Subpart A, Appendix B. Pursuant to 10 CFR 51.53(c)(3)(I), an applicant for license renewal may incorporate these generic findings in its environmental report. Analyses of the environmental impacts of license renewal that must be evaluated on a plant-specific basis (i.e., Category 2 issues) must be included in an environmental report in accordance with 10 CFR 51.53(c)(3)(ii).

In accordance with NEPA and the requirements of 10 CFR Part 51, the staff performed a plant-specific review of the environmental impacts of license renewal, including whether the GEIS considered all new and significant information. The staff then held a public meeting on November 6, 2002, near Ginna, as part of the NRC’s scoping process to identify environmental issues specific to the plant. The NRC then documented the results of the environmental review and its preliminary recommendation on the license renewal action in the draft plant-specific Supplement 14 to the GEIS, which was issued on June 25, 2003, and which was discussed at a separate public meeting on August 7, 2003, in Ontario, NY. After considering comments on the draft, the NRC prepared NUREG-1437, Supplement 14, “Generic Environmental Impact Statement for License Renewal of Nuclear Power Plants,” which was published on February 6, 2004.

1.3 Principal Review Matters

The requirements for renewing operating licenses for nuclear power plants are described in 10 CFR Part 54. The staff performed its technical review of the Ginna LRA in accordance with Commission guidance and the requirements of 10 CFR Part 54. The standards for renewing a license are contained in 10 CFR 54.29. This SER describes the results of the staff’s safety review.

In 10 CFR 54.19(a), the Commission requires a license renewal applicant to submit general information. The applicant provided this general information in Chapter 1 of its LRA for Ginna, submitted by letter dated July 30, 2002. The staff finds that the applicant has submitted the information required by 10 CFR 54.19(a) in Section 1 of the LRA.

In 10 CFR 54.19(b), the Commission requires that LRAs include “conforming changes to the standard indemnity agreement, 10 CFR 140.92, Appendix B, to account for the expiration term of the proposed renewed license.” The applicant stated the following in Section 1.3.8 of its LRA regarding this issue:

> The current indemnity agreement for the unit does not contain a specific expiration term for the operating license. Therefore, conforming changes to account for the expiration of the proposed renewed license are not necessary, unless the license number is changed upon issuance of the renewed license.

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

In 10 CFR 54.21, the Commission requires that each application for a renewed license for a nuclear facility contain (1) an IPA, (2) CLB changes during staff review of the LRA, (3) an evaluation of TLAAs, and (4) a UFSAR Supplement. Sections 3 and 4 and Sections A and B of the LRA address the license renewal requirements of 10 CFR 54.21(a), (c), and (d), respectively.

In 10 CFR 54.21(b), the Commission requires that each year following submittal of the application, and at least 3 months before scheduled completion of the staff's review, an amendment to the renewal application must be submitted that identifies any changes to the CLB of the facility that materially affect the contents of the LRA, including the UFSAR Supplement. The applicant submitted Amendment 1 to the LRA in a letter dated July 30, 2003, which summarized changes to the CLB that occurred at Ginna during the staff's review of the LRA. This submittal satisfies the requirement of 10 CFR 54.21(b).

In 10 CFR 54.22, the Commission states requirements regarding technical specifications. In Appendix D of the LRA, the applicant stated that no technical specification changes had been identified as being necessary to support issuance of the renewed operating licenses for Ginna. This adequately addresses the requirements of 10 CFR 54.22.

The staff evaluated the technical information required by 10 CFR 54.21 and 10 CFR 54.22 in accordance with the NRC's regulations and the guidance provided by the SRP-LR. The staff's evaluation of the LRA in accordance with 10 CFR 54.21 and 10 CFR 54.22 is contained in Sections 2, 3, and 4 of this SER.

The staff's evaluation of the environmental information required by 10 CFR 54.23 will be contained in the final plant-specific supplement to the GEIS, which will state the considerations related to renewing the license for Ginna. This will be prepared by the staff separate from this report. When the report of the ACRS, required by 10 CFR 54.25, is issued, it will be incorporated into Section 5 of an update to this SER. The findings required by 10 CFR 54.29 will be made in Section 6 of an update to this SER.

1.3.1 Westinghouse Topical Reports

In accordance with 10 CFR 54.17(e), the applicant referenced the following Westinghouse Commercial Atomic Power (WCAP) reports in the LRA.

- WCAP-7410-L, "Environmental Testing of Engineered Safety Feature Related Equipment (NSSS—Non-Standard Scope)"

- WCAP-7733, "Reactor Vessel Weld Cladding—Base Metal Interaction," July 1971

- WCAP-12928, “Structural Evaluation of the Robert E. Ginna Pressurizer Surge Line, Considering the Effect of Thermal Stratification,” May 1991

- WCAP-14422, Revision 2-A, “License Renewal Evaluation: Aging Management for Reactor Coolant Supports,” December 2000

- WCAP-14535A, “Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination,” SER published September 1996

- WCAP-14535A, “Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination,” republication November 1996

- WCAP-14574-A, “License Renewal Evaluation: Aging Management Evaluation for Pressurizers,” December 2000

- WCAP-14575-A, “Aging Management Evaluation for Class I Piping and Associated Pressure Boundary Components,” December 2000

- WCAP-14756-A, “Aging Management Evaluation for Pressurized Water Reactor Containment Structure,” May 2001

- WCAP-14577, Revision 1-A, “License Renewal Evaluation: Aging Management for Reactor Internals,” March 2001

- WCAP-15338, “A Review of Cracking Associated with Weld Deposited Cladding in Operating PWR Plants,” March 2000

- WCAP-15837, “Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the R.E. Ginna Nuclear Power Plant for the License Renewal Program,” April 2002

- WCAP-15873, “A Demonstration of the Applicability of ASME Code Case –481 to the Primary Loop Casings of R.E. Ginna Nuclear Power Plant for the License Renewal Program,” April 2002

- WCAP-15885, “R.E. Ginna Heatup and Cooldown Limit Curves for Normal Operation,” Revision 0, May 2002

The safety evaluations of the topical reports are intended to be stand-alone documents. An applicant that incorporates the topical reports by reference into an LRA must ensure that the conditions of approval stated in the safety evaluations are met. The staff’s evaluation of the applicant’s incorporation of the topical reports into the application is documented in Sections 3 and 4 of this SER.

1.4 Interim Staff Guidance

The license renewal program is a living program. The staff, industry, and other interested stakeholders gain experience and develop lessons learned with each renewed license. The lessons learned address the agency's performance goals of maintaining safety, improving effectiveness and efficiency, reducing regulatory burden, and increasing public confidence. The lessons learned are captured in interim staff guidance (ISG) for use by the staff and interested stakeholders until the improved license renewal guidance documents are revised.

The current set of relevant ISGs that have been issued by the staff, and the SER sections in which the issues are addressed by the staff, is provided below.

Interim Staff Guidance for License Renewal

ISG Issue (Approved ISG No.)	Purpose	SER Section
Station Blackout (SBO) Scoping (ISG-02)	The license renewal rule 10 CFR 54.4(a)(3) includes 10 CFR 50.63(a)(1)–SBO. The SBO rule requires that a plant must withstand and recover from an SBO event. The recovery time for offsite power is much faster than that of EDGs. The offsite power system should be included within the scope of license renewal.	2.5.1.5.2 3.5.2.4.2
Concrete Aging Management Program (ISG-03)	Lessons learned from the GALL demonstration project indicated that GALL is not clear whether concrete needs any AMPs.	3.5.2.2.1.1 3.5.2.2.2.2 3.5.2.4.1 3.5.2.4.2

ISG Issue (Approved ISG No.)	Purpose	SER Section
Fire Protection (FP) System Piping (ISG-04)	To clarify staff position for wall thinning of FP piping system in GALL AMPs (XI.M26 and XI.M27). New position is that there is no need to disassemble FP piping, as oxygen can be introduced in the FP piping which can accelerate corrosion. Instead, use nonintrusive method such as volumetric inspection. Testing of sprinkler heads should be performed before the end of the 50-year service life and at 10-year initials thereafter. Eliminated Halon/carbon dioxide system inspections for charging pressure, valve line ups, and automatic mode of operation test from GALL. The staff considers these test verifications to be operational activities.	3.3.2.3.2 3.3.2.3.3 3.3.2.4.6
Identification and Treatment of Electrical Fuse Holder (ISG-05)	To include fuse holder AMR and AMP (i.e., same as terminal blocks and other electrical connections). The position includes only fuse holders that are not inside the enclosure of active components (e.g., inside of switchgears and inverters). Operating experience finds that metallic clamps (spring-loaded clips) have a history of age-related failures from aging stressors such as vibration, thermal cycling, mechanical stress, corrosion, and chemical contamination. The staff finds that visual inspection of fuse clips is not sufficient to detect the aging effects from fatigue, mechanical stress, and vibration.	3.6.2.4.1.2

1.5 Summary of Open Items

As a result of its review of the LRA for Ginna, including additional information submitted to the NRC through September 9, 2003, the staff identified eight issues that remained open at the time this report was published previously as an SER with open items on October 9, 2003. An issue was considered open if the applicant had not presented a sufficient basis for resolution. Each open item was assigned a unique identifying number. By letters dated September 9, 2003, December 9, 2003, and December 19, 2003, the applicant responded to these open items. The staff reviewed the responses and has closed out all of the open items. The basis for closing the open items can be found in the following Sections—2.3.3.2, 2.3.3.3, 2.3.3.6, 2.5.1.1, 3.1.2.3.4, 3.1.2.3.7, 3.6.2.4.4, and 4.2.2.2.

1.6 Summary of Confirmatory Items

As a result of its review of the LRA for Ginna, including the additional information and clarifications that were submitted by the applicant to the NRC through September 9, 2003, the staff identified seven confirmatory items at the time this report was published previously as an SER with open items on October 9, 2003. An issue was considered confirmatory if the staff and applicant had reached a resolution of the issue, but the resolution had not yet been formally submitted to or reviewed by the staff. Each confirmatory item was assigned a unique identifying number. By letters dated September 9, 2003, December 9, 2003, December 19, 2003, and January 9, 2004, the applicant responded to these items. The staff reviewed the responses and has closed out all of the confirmatory items. The basis for closing the confirmatory items can be found in Sections 2.3.3.2, 2.3.3.5, 2.3.3.10, 3.3.2.3.4, 3.6.2.4.4, 4.3.2.2, and 4.3.2.7.

1.7 Summary of Proposed License Conditions

As a result of the staff's review of the Ginna application for license renewal, including the additional information and clarifications submitted subsequently, the staff identified two proposed license conditions. The first license condition requires the applicant to include the UFSAR Supplement in the next UFSAR update required by 10 CFR 50.71(e) following issuance of the renewed license. The second license condition requires that the future activities identified in the UFSAR Supplement be completed as specified in Appendix A of this SER.

2. SCOPING AND SCREENING METHODOLOGY FOR IDENTIFYING STRUCTURES AND COMPONENTS SUBJECT TO AGING MANAGEMENT REVIEW, AND IMPLEMENTATION RESULTS

This section documents the NRC staff's review of the methodology used by the applicant to identify structures, systems, and components (SSCs) that are within the scope of Title 10, Part 54, of the *Code of Federal Regulations* (the Rule), and to identify structures and components (SCs) that are within the scope of the Rule and are subject to an aging management review (AMR). Structures and components subject to an AMR are those that perform an intended function, as described in 10 CFR 54.4, and meet two criteria:

(1) They perform such functions without moving parts or without a change in configuration or properties, as set forth in 10 CFR 54.21(a)(1)(i) (denoted as "passive" SCs).

(2) They are not subject to replacement based on a qualified life or specified time period, as set forth in 10 CFR 54.21(a)(1)(ii) (denoted as "long-lived" SCs).

The identification of the SSCs within the scope of license renewal is called "scoping." For those SSCs within the scope of license renewal, the identification of "passive," "long-lived" SCs that are subject to an AMR is called "screening."

The staff's review of the scoping and screening methodology is presented in Section 2.1 of this safety evaluation report (SER). The staff's review of the results of the implementation of the scoping and screening methodology is presented in Sections 2.2 through 2.5 of this SER.

By letter dated July 30, 2002, the applicant submitted its request and application for renewal of the operating license for the R.E. Ginna Nuclear Power Plant (Ginna). As an aid to the staff during the review, the applicant provided evaluation boundary drawings that identify the functional boundaries for systems and components within the scope of license renewal. These evaluation boundary drawings are not part of the license renewal application (LRA).

On March 24 and March 28, 2003, the staff issued requests for additional information (RAIs) regarding the applicant's methodology for identifying SSCs at Ginna that are within the scope of license renewal and subject to an AMR and the results of the applicant's scoping and screening process. By letters dated April 11, May 13, May 23, June 3, and June 10, 2003, the applicant provided responses to the RAIs.

The staff conducted a scoping and screening inspection from June 23–27, 2003, to examine activities that supported the LRA, including the inspection of procedures and representative records and interviews with personnel regarding the process of scoping and screening plant equipment to select SSCs within the scope of the Rule and subject to an AMR. The inspection team did not identify any findings as defined in NRC Inspection Manual, Chapter 0612, "Power Reactor Inspection Report." On this basis, the NRC staff concluded that the applicant's scoping and screening process was successful in identifying those SSCs required to be considered for aging management. In addition, for a sample of plant systems, the inspection team performed visual examinations of accessible portions of the systems to observe any effects of equipment aging. Finally, the inspection concluded that the scoping and screening portion of the applicant's license renewal activities was conducted as described in the LRA and that documentation supporting the application is in an auditable and retrievable form.

2.1 Scoping and Screening Methodology

2.1.1 Introduction

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

In Section 2.0, "Scoping and Screening Methodology for Identifying Structures and Components Subject to Aging Management Review, and Implementation Results," of the LRA, the applicant described the scoping and screening methodology used to identify SSCs at Ginna within the scope of license renewal, as well as SCs that are subject to an AMR. The staff reviewed the applicant's scoping and screening methodology to determine if it meets the scoping requirements stated in 10 CFR 54.4(a) and the screening requirements stated in 10 CFR 54.21.

In developing the scoping and screening methodology for the Ginna LRA, the applicant considered the requirements of the Rule, the Statements of Consideration (SOCs) for the Rule, and the guidance presented by the Nuclear Energy Institute (NEI) in 95-10, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54—the License Renewal Rule," Revision 3, March 2001. In addition, the applicant also considered the NRC staff's correspondence with other applicants and with the NEI in the development of this methodology.

2.1.2 Summary of Technical Information in the Application

In Sections 2.0 and 3.0 of the LRA, the applicant provided the technical information required by 10 CFR 54.21(a). In Section 2.1, "Scoping and Screening Methodology," of the LRA, the applicant described the process used to identify the SSCs that meet the license renewal scoping criteria under 10 CFR 54.4(a), as well as the process used to identify the SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1). Additionally, Section 2.2, "Plant-Level Scoping Results," Section 2.3, "System Scoping and Screening Results: Mechanical Systems," Section 2.4, "Scoping and Screening Results: Structures," and Section 2.5, "Scoping and Screening Results: Electrical and Instrumentation and Controls Systems," of the LRA amplify the process that the applicant used to identify the SCs that are subject to an AMR. LRA Section 3, "Aging Management Review Results," contains the following information:

- Section 3.1, "Review Methodology"
- Section 3.2, "Aging Management of Reactor Coolant System"
- Section 3.3, "Aging Management of Engineered Safety Features Systems"
- Section 3.4, "Aging Management of Auxiliary Systems"

- Section 3.5, “Aging Management of Steam and Power Conversion Systems”
- Section 3.6, “Aging Management of Structures and Component Supports”
- Section 3.7, “Aging Management of Electrical and Instrumentation and Controls Systems”

Section 4 of the LRA, “Time-Limited Aging Analyses,” contains the applicant’s identification and evaluation of time-limited aging analyses (TLAAs).

2.1.2.1 Scoping Methodology

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

2.1.2.1.1.1 Safety-Related Criteria in Accordance with 10 CFR 54.4(a)(1). In LRA Sections 2.1.3, “System and Structure Function Determination,” 2.1.4, “Design Codes, Standards, and SSC Safety Classifications,” and 2.1.5, “Application of License Renewal Scoping Criterion,” the applicant discussed the scoping methodology as it related to the safety-related criteria in accordance with 10 CFR 54.4(a)(1). With respect to the safety-related criteria, the applicant stated that the SSCs determined to be safety-related, by review of the safety classification scheme established at the site, were included within the scope of license renewal.
The applicant described the site safety classification scheme in Section 2.1.5.1 of the LRA. The safety classification scheme was recorded in the applicant’s controlled Configuration Management Information System (CMIS) database, which was used extensively during the LRA scoping activities. The applicant stated in Section 2.1.4 of the LRA that the safety classification process provided a comprehensive review of plant SSCs using the guidance contained in American National Standards Institute (ANSI)/American Nuclear Society (ANS)-51.1-1983. Based on functional rules, plant SSCs were designated as safety class 1 (SC-1), safety class 2 (SC-2), safety class 3 (SC-3), safety significant (SS), and nonnuclear safety (NNS).
The applicant concluded that the functional safety-related criterion used in the safety classification process encompasses the definition of safety-related specified in 10 CFR 54.4(a)(1). Consequently, components designated as SC-1, -2, or -3 were considered to be within the scope of license renewal.

The scoping results for safety-related SSCs, based on the safety classification program were supplemented by reviews of the updated final safety analysis report (UFSAR), technical specifications, design documents, and design drawings to ensure that all system functions were identified and considered. The applicant concluded that the scoping process used to identify safety-related systems and structures was consistent with, and satisfied the criteria of, 10 CFR 54.4(a)(1).

2.1.2.1.1.2 Nonsafety-Related Criteria in Accordance with 10 CFR 54.4(a)(2). In Section 2.1.5.2, “Nonsafety-Related Criteria Pursuant to 10 CFR 54.4(a)(2) (Criterion 2),” of the LRA, the applicant discussed the scoping methodology as it related to the nonsafety-related criteria, in accordance with 10 CFR 54.4(a)(2). With respect to the nonsafety-related criteria, the applicant stated, in part, that a review had been performed to identify the nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of the safety-related intended functions identified in 10 CFR 54.4(a)(1). The applicant used a two-phase process to identify SSCs meeting the criteria of 10 CFR 54.4(a)(2). The applicant initially identified SSCs meeting the 10 CFR 54.4(a)(2) scoping criteria using an analytical review process which considered nonsafety-related equipment explicitly identified in the current licensing basis (CLB). However, the applicant determined that the sole use of the analytical review process did not provide information relative to system spatial interactions. Therefore, the initial analytical phase was augmented with a plant spaces physical review to identify possible interactions not functionally described in the CLB. The various phases of the review are described in the following paragraphs.

Analytical Review Process. As described in Section 2.1.5.2 of the LRA, the applicant stated that some nonsafety-related equipment whose failure could affect a safety-related function was specifically identified within the plant safety classification program. The applicant reviewed the safety classification program functional rules to identify SSC functions that met the 10 CFR 54.4(a)(2) scoping criteria. A preliminary listing of nonsafety-related SSCs meeting the scoping criteria of 10 CFR 54.4(a)(2) was then generated by querying the CMIS database to identify SSCs with functional designators associated with license renewal intended functions. The applicant stated that the safety classification functional rules allowed identification of systems containing components that were—

- credited for high-energy line break (pipe whip, jet impingement)
- credited for internal flooding (barriers, drains)
- credited for external flooding
- credited for internal missiles
- load handling equipment credited for NUREG-0612
- alternate/backup systems or equipment credited in mitigating licensing-basis events

The applicant stated that the analytical process used to review SSCs for 10 CFR 54.4(a)(2) applicability ensured that the UFSAR, technical specifications, design documents, design drawings, and SSC safety classifications were reviewed, as appropriate, to make certain that all nonsafety-related SSC functional interactions were identified for those instances in which nonsafety-related SSCs could fail and prevent the satisfactory accomplishment of a safety function.

Plant Spaces Physical Review. As discussed in Section 2.1.5.4 of the LRA, in plant areas containing safety-related equipment, field verifications were performed to ascertain if any systems or system piping segments meeting the 10 CFR 54.4(a)(2) criteria were present that had not already been included within the scope of license renewal based on the analytical review. If a newly identified system or piping segment had a failure mode or effect that met the scoping criteria of 10 CFR 54.4(a)(2), the applicant stated that the system or segment was included within the scope of license renewal.

In certain cases, the applicant stated that both mitigative features and preventive aging management techniques were applied to nonsafety-related equipment whose failure could affect a safety function. Mitigative features were intended to protect safety-related equipment in the event of a postulated nonsafety-related piping failure, while preventive measures were intended to manage the adverse effects of aging on the nonsafety-related equipment. The applicant stated that the mitigative features credited in protecting safety-related equipment were placed within the scope of license renewal. In those cases in which preventive measures were used, the applicant placed the associated fluid system components within the scope of license renewal.

In Section 2.1.6, “Interim Staff Guidance Discussion,” of the LRA, the applicant stated that previous staff issues associated with the interpretation of the 10 CFR 54.4(a)(2) scoping criteria were addressed by the two-phase scoping approach. Specifically, the plant spaces physical review evaluated SSCs for possible interactions that were not explicitly described in the plant CLB. The applicant concluded that the 10 CFR 54.4(a)(2) criteria were applied such that nonsafety-related SSCs were identified as being within the scope of license renewal when there was a potential of either physical or spatial interaction with the intended function of safety-related equipment.

2.1.2.1.1.3 <u>Nonsafety-Related Criteria in Accordance with 10 CFR 54.4(a)(3)</u>. In Section 2.1.5.5, “Other Scoping Pursuant to 10 CFR 54.4(a)(3) (Criterion 3),” of the LRA, the applicant discussed the scoping methodology as it related to the regulated event criteria in accordance with 10 CFR 54.4(a)(3). With respect to the scoping criteria related to 10 CFR 54.4(a)(3), the applicant stated that the analytical process used to review SSCs for 10 CFR 54.4(a)(3) applicability ensured that the UFSAR, technical specifications, design documents, design drawings, and plant safety classifications were reviewed, as appropriate, to make certain that all SSCs credited for compliance with the regulated event set were identified. The applicant concluded that the scoping process used to identify systems and structures relied upon to mitigate the regulated events of concern were consistent with, and satisfied the criteria of, 10 CFR 54.4(a)(3). Specific scoping information based on the five regulated events described in 10 CFR 54.4(a)(3) presented in the following paragraphs.

<u>Fire Protection (10 CFR 50.48)</u>. In Section 2.1.5.6 of the LRA, the applicant described the methodology used to scope SSCs associated with fire protection. All fire protection, detection, mitigation, confinement, and safe shutdown equipment used at the station was subject to a scoping review. Evaluations were made of equipment needed to meet the fire protection requirements of Appendix A to Branch Technical Position (BTP) ASB 9.5-1, as well as those needed to meet the requirements of 10 CFR 50.48 and Appendix R to 10 CFR Part 50. These evaluations were used as fire protection scoping basis documents. All structures and systems that contain components used for fire protection of the SSCs important to safety were within the scope of license renewal. The applicant noted in the LRA that many of the site structures not important to safety also have fire detection and mitigation capabilities. In these cases in which a fire protection system was not credited in the CLB as important to safety, the system and the SSCs it protected were not considered to be within the license renewal scope.

<u>Environmental Qualification (10 CFR 50.49)</u>. Section 2.1.5.7 of the LRA described the applicant’s methodology for scoping SSCs associated with environmental qualification (EQ). The applicant stated that the master list of EQ components was detailed in site-specific procedures. All systems that contain components detailed on the EQ master equipment list were considered to be within the scope of license renewal.

Pressurized Thermal Shock (10 CFR 50.61). Section 2.1.5.8 of the LRA described the applicant's methodology for scoping SSCs associated with pressurized thermal shock (PTS). The applicant stated that Rochester Gas & Electric Corporation (RG&E) has made two submittals to the NRC regarding PTS. The applicant determined that these submittals and NRC SERs did not identify the need for specific plant hardware modifications or reliance on other plant systems. Consequently the only SSC credited in the PTS analysis was the reactor vessel, which was considered to be within the scope of license renewal.

Anticipated Transients Without Scram (10 CFR 50.62). Section 2.1.5.9 of the LRA describes the applicant's methodology for scoping SSCs relied upon to function to mitigate anticipated transients without scram (ATWS). The applicant determined that all equipment installed, from the sensor output to the final actuation device, that was credited for compliance with 10 CFR 50.62, was within the scope of license renewal.

Station Blackout (10 CFR 50.63). Section 2.1.5.10 of the LRA described the applicant's methodology for scoping SSCs relied upon to perform a function during station blackout (SBO) events. The SBO scoping strategy basis reference documents include both primary and alternative SSCs available to manage the event. Systems and structures that provided a function for SBO scoping, and systems or structures that provided a function for recovery from an SBO condition, were considered within the scope of license renewal. In Section 2.1.6 of the LRA, the applicant stated that the SBO scoping methodology was consistent with the interim staff guidance on scoping of equipment relied on to meet the requirements of the SBO rule.

In summary, the applicant stated that the scoping process used to identify SCs relied on to mitigate the regulated events of concern is consistent with, and satisfies the criteria of, 10 CFR 54.4(a)(3).

2.1.2.1.2 Documentation Sources Used for Scoping and Screening

In Section 2.1.1 of the LRA, the applicant stated information derived from the UFSAR, technical specifications, licensing correspondence files, design-basis documents (DBDs), controlled drawings, the Q-list, and the CMIS electronic database was reviewed during the license renewal scoping and screening process. The applicant used this information to identify the functions performed by plant systems and structures. These functions were then compared to the scoping criteria in 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3) to determine if the associated plant system or structure performed a license renewal intended function. These sources were also used to develop the list of SSCs subject to an AMR.

2.1.2.1.3 Plant- and System-Level Scoping

In Section 2.1 of the LRA, the applicant described the scoping methodology for systems and structures that were safety-related, nonsafety-related, and equipment relied upon to perform a function for any of the five regulated events described in 10 CFR 54.4(a)(3).

The applicant initially defined license renewal system boundaries for systems and structures to facilitate scoping and screening. The applicant stated that license renewal system boundaries were based on the preexisting CMIS database system identifiers, but were adjusted to be more consistent with UFSAR system descriptions. The applicant stated that the use of unique license renewal system boundaries did not impact the ability to identify system and structure intended functions because the results of the functionally based SSC safety classification program remained valid, regardless of the system naming or sorting scheme. During scoping evaluations, if the system under review contained any components that met the license renewal scoping criteria detailed in 10 CFR 54.4(a), the applicant generally considered the entire system to be within the scope of license renewal. Additionally, in Section 2.1.3 of the LRA, the applicant stated that system scoping must identify all license renewal functions associated with components contained within a system. The applicant identified two specific exceptions to this dictate in the LRA:

(1) When the only in-scope portion of the system comprises components that will receive a commodity group evaluation (e.g., fire barriers, equipment supports, etc.), the applicant could identify the parent system or structure as not being within the scope of license renewal.

(2) When the only in-scope portion of the system comprises components that act as containment isolation boundaries, the applicant stated that the system could be identified as not being within the scope of license renewal. This would only be true if the components that perform the isolation boundary function were evaluated within the containment isolation boundary system.

The applicant concluded that the critical element of system scoping is to ensure that all SSCs that perform license renewal intended functions are identified and the criteria that brought them into scope are documented.

2.1.2.1.4 Component-Level Scoping

After the applicant identified the intended functions of systems or structures within the scope of license renewal, a review was performed to determine which components of each in-scope system and structure supported license renewal intended functions. The components that supported intended functions were considered within the scope of license renewal and screened to determine if an AMR was required. The applicant considered three component classifications during this stage of the scoping methodology—mechanical, civil and structural, and electrical. The scoping methodology for each of these component classifications is discussed below.

2.1.2.1.4.1 Mechanical Component Scoping. The applicant described the scoping methodology for components within mechanical systems in Section 2.1.7.1 of the LRA. For mechanical systems, the applicant stated that the component/structural component scoping and screening process was performed on each system identified to be within the scope of license renewal. This process evaluated the individual SCs included within the in-scope mechanical systems to identify the specific SCs that required an AMR. Electrical interface components associated with mechanical systems that were determined to be in scope were evaluated under the electrical component scoping methodology.

Mechanical system evaluation boundaries were established for each system within the scope of license renewal. These boundaries were determined by mapping the pressure boundary associated with system-level license renewal intended functions onto the system piping and instrumentation drawings (P&IDs). The applicant stated that the following sequence of steps was used for component-level scoping for each mechanical system within the scope of license renewal.

(1) The applicant identified mechanical components included within each system by reviewing design drawings and the system component list from the CMIS database.

(2) Based on the plant-level system scoping results, the pressure boundary associated with license renewal system intended functions was mapped onto the system P&IDs. The applicant stated that the license renewal evaluation boundary on system flow diagram markups was typically extended to the first normally closed manual valve, check valve, or valve that received an automatic closure signal. The LRA stated that a normally open manual valve had also been used as a boundary in a few instances in which a failure downstream of the valve has no short term effects, could be quickly detected, and the valve could be easily closed by operators to establish the pressure boundary prior to any adverse consequences. For SBO, Appendix R, high-energy line break (HELB) and flooding events, the license renewal boundaries for a system were defined to be consistent with the boundaries established in the CLB evaluations and did not always coincide with an isolation device.

    As discussed in Section 2.1.5.3 of the LRA, for piping interfaces between safety-related and nonsafety-related systems, the P&IDs show safety classification boundaries at valves. However, actual safety boundaries extended to the first weld after the first seismic support beyond the P&ID depicted class change. The piping within the license renewal boundary was subject to AMR and was included as a piping commodity considered to be within the scope of license renewal.

(3) The system components that were within the scope of license renewal (i.e., required to perform a license renewal system intended function) were identified.

(4) Component intended functions for in-scope components were identified. The applicant stated that component intended functions were based on the guidance of NEI 95-10.

The applicant forwarded in-scope mechanical SCs to a screening review to determine if the equipment was subject to an AMR.

2.1.2.1.4.2 Structural Component Scoping. The applicant described the methodology for scoping civil and structural equipment in Section 2.1.7.2 of the LRA. For structures, the SC scoping and screening process was performed on each plant-level structure identified to be within the scope of license renewal. This method evaluated the individual SCs included within in-scope structures to identify specific SCs or SC groups that required an AMR. The following sequence of steps was performed on each structure determined to be within the scope of license renewal.

(1) Based on a review of design drawings, the structure component list from the CMIS database and plant walkdowns, SCs that were included within the structure were identified. These SCs included items such as walls, pipe and equipment supports, conduit, cable trays, electrical enclosures, instrument panels, and related supports.

(2) The plant CLB was reviewed and compared to the walkdown results. Appurtenances, such as flood barriers, missile shields, jet impingement shields, etc., relied upon in the licensing basis were verified as accounted for within a structure.

(3) The SCs within the scope of license renewal (i.e., required to perform license renewal system intended functions) were identified, as were component intended functions for in-scope SCs. The component intended functions identified were based on the guidance of NEI 95-10.

The applicant identified materials, such as caulking and water stops, generically. The applicant stated that these materials supported only two license renewal structure or component intended functions. Specifically, these materials supported (1) providing a rated fire barrier and (2) providing a flood barrier. Sealants and caulking that support the fire barrier function were addressed as part of the fire barrier penetration seals. Water stops that support the flood barrier function were addressed with the wall or floor within which the sealant/water stop was contained. Flood barriers were addressed in the buildings that contain them.

In Section 2.1.7.3 of the LRA, the applicant described the use of structural commodity groups for civil and structural component-level scoping. Two structural commodity evaluation groups were identified as within the scope of license renewal:

(1) fire doors, barrier penetration seals, and wraps
(2) racks, panels and electrical enclosures, pipe, and equipment supports

The applicant forwarded in-scope civil and structural components to a screening review to determine if the equipment was subject to an AMR.

2.1.2.1.4.3 Electrical and Instrumentation and Controls Component Scoping. In Section 2.1.7.4 of the LRA, the applicant described the scoping and screening methodology for electrical and instrumentation and controls (I&C) system components. The applicant performed screening for electrical and I&C components on a generic component commodity group basis for all electrical and I&C systems and components associated with in-scope mechanical systems and civil structures. The applicant initially considered all passive long-lived electrical and I&C commodity groups as being subject to an AMR. The methodology permitted component-specific scoping to identify any equipment within the commodity group that did not perform an intended function in order to reduce the number of components for which aging management activities were required. The applicant stated that the methodology employed was consistent with the plant spaces electrical scoping and screening approach described in NEI 95-10 and NUREG-1800.

2.1.2.2 Screening Methodology

Following the determination of SSCs within the scope of license renewal, the applicant implemented a process for determining which SSCs would be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). In Section 2.1.7, "Component-Level Screening (Identification of Components Subject to Aging Management Review)," of the LRA, the applicant discussed the screening activities as they related to the SSCs that are within the scope of license renewal. The screening portion of the integrated license renewal plant assessment was divided into three engineering disciplines—mechanical, civil/structural, and electrical and I&C.

2.1.2.2.1 Mechanical Component Screening

Following component-level scoping for mechanical systems, the applicant performed screening to identify those mechanical components that were subject to an AMR. The applicant stated in LRA Section 2.1.7.1, "Mechanical Systems," that the following screening methodology was used:

- The in-scope SCs that perform an intended function without moving parts or without a change in configuration or properties (screening criterion of 10 CFR 54.21(a)(1)(i)) were identified. Active/passive screening determinations were based on the guidance in Appendix B to NEI 95-10.

- The passive, in-scope SCs that were not subject to replacement based on a qualified life or specified time period (screening criterion of 10 CFR 54.21(a)(1)(ii)) were identified as requiring an AMR. The determination of whether passive, in-scope SCs have a qualified life or specified replacement time period was based on a review of plant-specific information, including the component database, maintenance programs, and procedures.

In Section 2.1.6, "Interim Staff Guidance Discussion," of the LRA, the applicant described the screening methodology used for the housings of active components. The applicant stated that the exclusion of an SSC due to its active nature applied only to that portion of the SSC with an active function and not to those portions of the SSC with a passive function. Therefore, the applicant considered fan housings and fire damper housings to be within the scope of license renewal and subject to an AMR.

2.1.2.2.2 Structural Component Screening

Following component-level scoping for structures, the applicant performed screening to identify those civil/structural components that were subject to an AMR. In Section 2.1.7.2, "Civil Structures," of the LRA, the applicant described the methodology used to screen civil/structural components. The applicant stated that the following civil/structural screening methodology was used:

- The in-scope SCs that perform an intended function without moving parts or without a change in configuration or properties (screening criterion of 10 CFR 54.21(a)(1)(i)) were identified. Active/passive screening determinations were based on the guidance in Appendix B to NEI 95-10.

- The passive, in-scope SCs that were not subject to replacement based on a qualified life or specified time period (screening criterion of 10 CFR 54.21(a)(1)(ii)) were identified as requiring an AMR. The determination of whether a passive, in-scope SC has a qualified life or specified replacement time period was based on a review of plant-specific information, including the component database, maintenance programs and procedures, vendor manuals, and plant experience.

Structural steel, anchor bolts, base plates, etc., that were required to support nonsafety-related components to prevent physical interactions with safety-related equipment were subject to AMRs.

2.1.2.2.3 Electrical and Instrumentation and Controls Component Screening

Following component-level scoping for electrical and I&C systems, the applicant performed screening to identify those electrical and I&C components that were subject to an AMR. The applicant described the screening methodology for electrical and I&C components in Section 2.1.7.4, "Electrical and I&C Systems," of the LRA. Screening for electrical and I&C components was performed on a generic component commodity group basis for all electrical and I&C systems, as well as the electrical and I&C component commodity groups associated with in-scope mechanical systems and civil structures. The boundary components for the electrical and I&C component review were the incoming 34.5 kilovolt (kV) switchyard bus breakers and the generator step-up transformer. These reference points represented the transition from site-controlled power systems to the power systems maintained as part of the local distribution grid. The applicant stated that the methodology employed was consistent with the guidance in NEI 95-10 and NUREG-1800.

Screening for electrical and I&C system commodity groups used the plant spaces approach and a bounding review technique. Using this methodology, initially all passive, long-lived electrical and I&C commodity groups were initially considered subject to an AMR. A review of the UFSAR, the plant's database, and DBDs was performed to validate the commodity group applicability to the Ginna Station. Within a plant area, the applicant identified the commodity group that represented the limiting aging characteristics. The selected commodity was compared to the plant space service conditions and an assessment was made to determine whether the commodity group would be able to maintain its function for the period of extended operation (i.e., receives an AMR).

Based on the screening results, component-specific scoping could be performed to reduce the number of components within a commodity group for which aging management activities were required. Additionally, components within the scope of 10 CFR 50.49 (Environmental Qualification) were subject to replacement and therefore not subject to an AMR based on the screening criteria of 10 CFR 54.21(a)(1)(ii). The applicant stated that this approach for EQ equipment was supported by NUREG-1800, Section 2.5.3.

In Section 2.1.6 of the LRA, the applicant described the approach used for the treatment of electrical fuse holders. Consistent with the requirements specified in 10 CFR 54.4(a), fuse holders (including fuse clips and fuse blocks) were considered to be passive electrical components. Fuse holders were scoped, screened, and included in the AMR in the same manner as terminal blocks and other types of electrical connections. Fuse holders were therefore passive, long-lived electrical components within the scope of license renewal and subject to an AMR. Therefore, aging management of the fuse holders was required for those cases in which fuse holders were not considered piece parts of a larger assembly. However, fuse holders inside the enclosure of an active component, such as switchgear, power supplies, power inverters, battery chargers, and circuit boards, were considered to be piece parts of the larger assembly. Since piece parts and subcomponents in such an enclosure were inspected regularly and maintained as part of the Ginna Station normal maintenance and surveillance activities, they were considered not subject to an AMR.

2.1.3 Staff Evaluation

The staff evaluated the LRA scoping and screening methodology in accordance with the guidance contained in Section 2.1, "Scoping and Screening Methodology," of NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants." The acceptance criteria for scoping and screening methodology review is based on the following regulations:

- 10 CFR 54.4(a), as it relates to the identification of plant SSCs within the scope of the Rule

- 10 CFR 54.4(b), as it relates to the identification of the intended functions of plant SSCs determined to be within the scope of the Rule

- 10 CFR 54.21(a)(1) and 10 CFR 54.21(a)(2), as they relate to the methods utilized by the applicant to identify plant SCs subject to an AMR as part of the review of the applicant's LRA, the NRC staff evaluated the scoping and screening methodology described in the following sections of the application using the guidance contained in NUREG-1800:

  - Section 2.1, "Scoping and Screening Methodology," to ensure that the applicant describes a process for identifying SSCs that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3)

  - Section 2.2, "Plant-Level Scoping Results," Section 2.3, "Scoping and Screening Results: Mechanical Systems," Section 2.4, "Scoping and Screening Results: Structures," and Section 2.5, "Screening Results: Electrical and Instrumentation and Control Systems," to assure the applicant described a process for determining structural, mechanical, and electrical components at Ginna that are subject to an AMR for renewal in accordance with the requirements of 10 CFR 54.21(a)(1) and 10 CFR 54.21(a)(2).

In addition, the staff conducted a scoping and screening methodology audit at Ginna from December 10 to 13, 2002. The focus of the audit was to ensure that the applicant had developed and implemented adequate guidance to conduct the scoping and screening of SSCs in accordance with the methodologies described in the application and the requirements of the Rule. The staff reviewed implementation procedures and engineering reports which describe the scoping and screening methodology implemented by the applicant. In addition, the staff conducted detailed discussions with the cognizant license renewal project staff on the implementation and control of the program, reviewed administrative control documentation, and selected design documentation used by the applicant during the scoping and screening process. The staff further reviewed a sample of system scoping and screening results reports for the auxiliary feedwater, component cooling water (CCW), main steam, and main feedwater systems to ensure the methodology outlined in the administrative controls was appropriately implemented.

2.1.3.1 Scoping Methodology

2.1.3.1.1 Documentation Sources Used for Scoping and Screening

The staff reviewed implementation procedures and engineering reports which describe the scoping and screening methodology implemented by the applicant. These procedures included (1) EP-3-S-0712, "License Renewal Project Guideline," Revision 0, (2) EP-3-S-0713, "Scoping and Screening for License Renewal," Revision 1, (3) EP-3-S-0714, "Mechanical Aging Management Review for License Renewal," Revision 1, (4) EP-3-S-0901, "Records and Document Control," Revision 7, (5) EG-012, "Scoping and Screening and Mechanical AMRs," Revision 1, (6) EG-014, "Data Retrieval to Begin License Renewal Project," Revision 0, (7) EG-015, "License Renewal Issues Management ," Revision 0, (8) EG-017, "Ginna Operating Experience Failure Data Retrieval," Revision 0, (9) EP-3-S-0715, "Electrical Aging Management Review for License Renewal," Revision 0, (10) EP-3-S-0716, "Civil Aging Management Review for License Renewal," Revision 1, and (11) EP-3-S-0718, "Electrical and I&C Integrated Plant Assessment Documents for License Renewal," Revision 0. In reviewing these procedures, the staff focused on the consistency of the detailed procedural guidance with information in the LRA and the various NRC staff positions documented in NUREG-1800 and interim staff guidance documents. The staff found that the scoping and screening methodology instructions were consistent with Section 2.1 of the LRA and were of sufficient detail to provide the applicant's staff with concise guidance on the scoping and screening implementation process to be followed during the LRA activities.

Engineering procedure EP-3-S-0713 identified the UFSAR, system descriptions, the plant probabilistic risk assessment, the CMIS database, plant drawings, the maintenance rule program, and system functional reports as potential sources of information regarding systems and structures required to remain functional during and following design-basis events.

Additionally, the applicant's safety classification program, described in procedure IP-QAP-1, "Structure, System, and Component Safety Classifications," included detailed descriptions of component- and system-level functions, in addition to safety classification data. For each evaluated component, the applicant identified component-level functions. System function reports (SFRs) were developed to support and document the safety classification of systems and structures. The SFRs consider design-basis events and certain special events, but may not describe system functions not considered during the safety classification process. The applicant linked the component-level functions to the higher-level system-level functions using proceduralized safety classifications rules. This safety classification methodology provided the applicant with detailed information regarding the intended functions of evaluated components. Therefore, the applicant's safety classification methodology provided a detailed breakdown of component-level functions, associated system-level functions, and the component safety classification for safety-related and nonsafety-related safety significant SSCs. The applicant maintained SSC safety classification data in the CMIS database.

The applicant did not maintain a written DBD for each plant system, but instead utilized a virtual DBD system, accessible in the CMIS database, to support the identification of SSC intended functions. The applicant's CMIS database included basic keyword and SSC indexing information for design criteria and analyses, engineering specifications, 10 CFR 50.59 evaluations, vendor design analyses, and correspondence. The applicant's records and document control procedures, described in procedure EP-3-S-0901, "Records and Document Control," required that the DBDs be electronically imaged and cross referenced to the associated systems and components to support document retrieval. Using document keyword and indexing data, the applicant generated virtual DBDs by performing queries of the CMIS database. During the scoping and screening audit, the staff concluded that the virtual DBD system required a knowledgeable and skilled evaluator to effectively identify system intended functions. Specifically, because user-generated CMIS queries are used to retrieve relevant system DBDs, an improper or incomplete CMIS query could result in a failure to identify all relevant system functions. However, based on discussions with the applicant's license renewal project staff, the staff concluded that the license renewal reviewers were skilled in generating virtual DBD data and were knowledgeable of database limitations.

Based on discussions with the applicant's license renewal staff, the staff determined that the applicant's document review methodology adequately integrated safety classification data, the UFSAR, SFRs, and the virtual DBDs. The staff found these design documentation sources to be useful for ensuring that the initial scope of SSCs identified by the applicant was consistent with the CLB of the Ginna plant. Additionally, the staff concluded that license renewal team members were familiar with the content and limitations associated with the various sources of information used in the development of the LRA. The staff determined that the documentation review methodology used by the applicant was capable of identifying system intended functions as necessary to support SSC scoping and screening consistent with the guidance in NUREG-1800. Additionally, the documentation review methodology was consistent with the applicant's LRA and plant procedures.

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

2.1.3.1.2.1. Application of the Scoping Criteria in 10 CFR 54.4(a)(1). As required by 10 CFR 54.4(a)(1), the applicant must consider all safety-related SSCs which are relied upon to remain functional during and following design-basis events to ensure (1) the integrity of the reactor coolant pressure boundary, (2) the ability to shut down the reactor and maintain it in a safe shutdown condition, or (3) the capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to those referred to in 10 CFR 50.34(a)(1), 10 CFR 50.67(b)(2), or 10 CFR 100.11 as being within the scope of the license renewal.

Section 5.1.2 of engineering procedure EP-3-S-0713 contains guidance for the scoping of safety-related systems and structures. As part of the safety classification program, the applicant had previously identified safety-related SSCs in accordance with interface procedure IP-QAP-1. In general, the applicant categorized systems that contained safety-related components to be within the scope of license renewal scoping criterion 10 CFR 54.4(a)(1). However, the applicant noted in procedure EP-3-S-0713 that equipment that was designated as safety-related, but which did not perform an intended function described in 10 CFR 54.4(a)(1), would not necessarily be considered within the scope of license renewal. In Section 2.1.5.1 of the LRA, the applicant stated that the safety-related criteria used in the SSC safety classification process encompassed the 10 CFR 54.4(a)(1) scoping criteria.

The staff reviewed the safety classification guidance contained in interface procedure IP-QAP-1 to determine if the applicant's safety-related classification definition was consistent with 10 CFR 54.4(a)(1). The staff reviewed the safety classification rules contained in the applicant's administrative procedure IP-QAP-1 and sampled the applicant's scoping results reports to verify the process by which these SSCs were initially identified. As a result of this review, the staff determined that additional information was necessary to document how the safety classification rules were specifically applied to identify in-scope SSCs. For example, Section 2.1.5.3 of the LRA implies that nonsafety-related SSCs credited for internal missiles were identified using the safety classification rules; however, it was not readily apparent which safety classification rule contained in IP-QAP-1 applies to this equipment. The staff was also unable to directly link the safety-related scoping criteria of 10 CFR 54.4(a)(1) to specific safety classification rules contained in IP-QAP-1. By letter dated March 21, 2003, the staff requested that the applicant provide additional clarification on how the classification rules were applied to the SSCs initially identified as within scope. This is RAI 2.1-1.

By letter dated May 13, 2003, the applicant provided a response to the request for information. In that response, the applicant provided a detailed listing of the safety classification rules applicable to the safety-related, nonsafety-related, and regulated event SSCs within scope. The staff has reviewed that listing and finds that it adequately addressed the staff's concern regarding the internal missiles example cited above, as well as describing all pertinent safety classification rules applied to the scoping effort related to components that were credited for various design-basis events, such as HELB, internal flooding, external flooding, internal missiles, and load handling, in a comprehensive manner. In addition to the safety classification rules, the applicant noted that for the EQ evaluation the station EQ master list was utilized for the scoping of environmentally qualified equipment. Therefore RAI 2.1-1 is considered resolved.

As required by 10 CFR 54.4(a)(1)(iii), the applicant must consider within the scope of license renewal those SSCs that ensure the capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to those referred to in 10 CFR 50.34(a)(1), 10 CFR 50.67(b)(2), or 10 CFR 100.11. Although the wording in Section 2.1.2, "Plant-Level Scoping," of the LRA was consistent with this requirement, the staff noted that the scoping criteria definition documented in Section 3.2.1 of EP-3-S-0713, Revision 1, differed from the wording in 10 CFR 54.4(a)(1)(iii). Specifically, the EP-3-S-0713 safety-related scoping definition did not refer to offsite exposures comparable to those referred to in 10 CFR 50.34(a)(1) and 10 CFR 50.67(b)(2). As a result, in a letter dated March 21, 2003, the staff requested additional information regarding how these exposure limitations were factored into the license renewal scoping and screening process. This is RAI 2.1-2.

By letter dated May 23, 2003, the applicant provided additional information regarding the expanded definition for offsite exposures. In its response, the applicant stated, in part, that the values in 10 CFR 50.34(a)(1) are bounded by those provided in 10 CFR 100.11 (25 roentgen equivalent man (rem) whole body equals 25 rem total effective dose equivalent (TEDE) and 300 rem thyroid equals 9 rem TEDE), so only the limiting value was used in the procedure. The applicant further noted that 10 CFR 50.67(a)(2) applies to licensees who seek to revise their accident source term in design basis radiological consequence analyses, and that it did not seek to revise its source term. The applicant further addressed the question by noting that procedure EP-3-S-0713 has been updated to reflect these two regulations because the in-scope equipment for license renewal is the same. The staff has reviewed the applicant's response and finds it acceptable based on the recognition that the limiting values were used for the evaluation, and the requirements associated with the revised source term (10 CFR 50.67(a)(2)) did not impact its evaluation because the applicant did not seek to implement the revision. Therefore RAI 2.1-2 is considered resolved.

As part of the review of the applicant's scoping methodology, the staff reviewed a sample of the license renewal database 10 CFR 54.4(a)(1) scoping results, and a sample of the analyses and documentation to support these reviews. The staff also discussed the methodology and results with the applicant's personnel responsible for these evaluations. The staff verified that the applicant had identified and used pertinent engineering and licensing information to determine the SSCs required to be in scope in accordance with the 10 CFR 54.4(a)(1) criteria. On the basis of this sample review, discussions with the applicant, and evaluation of the applicant's responses to the staff's requests for additional information, the staff determined that the applicant's methodology for identifying systems and structures meeting the scoping criteria of 10 CFR 54.4(a)(1) was adequate.

2.1.3.1.2.2 <u>Application of the Scoping Criteria in 10 CFR 54.4(a)(2)</u>. As required by 10 CFR 54.4(a)(2), the applicant must consider all nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs 10 CFR 54.4(a)(1)(i), 10 CFR 54.4(a)(1)(ii), or 10 CFR 54.4(a)(1)(iii) to be within the scope of license renewal. As part of the review, the staff evaluated the implementation guidance developed by the applicant to govern its 10 CFR 54.4(a)(2) evaluation, discussed the process and results with the applicant's cognizant license renewal project staff, and reviewed a sample of the scoping results developed by the applicant.

As described in Section 2.1.2.1.1 of this SER, the applicant used a two-phase process for the scoping of nonsafety-related systems and structures. During initial scoping evaluations, the applicant employed an analytical review approach to identify SSCs meeting 10 CFR 54.4(a)(2) that were specifically identified in the plant CLB. To identify potential spatial interactions, the licensee performed a plant spaces physical review to identify SSCs that could affect safety functions that were not explicitly described in the CLB.

The applicant initially developed two guidelines to control the evaluation process. Section 5.1.3 of engineering procedure EP-3-S-0712 contained guidance for the scoping of these nonsafety-related systems and structures. This document specifically described that the review did not require consideration of hypothetical failures that were not part of the CLB, and that the scoping reviewer should consider those failures identified in the documentation that makes up the CLB, plant-specific operating experience, and industry operating experience that was specifically applicable to Ginna. Additionally, engineering guideline EG-021, "Identification of Non Safety Equipment Whose Failure Could Affect a Safety Function for Scoping and Screening," provided additional guidance for identifying nonsafety-related equipment that met the 10 CFR 54.4(a)(2) scoping criteria.

The applicant generated a preliminary list of nonsafety-related SSCs that could affect a safety function by querying the CMIS database to identify nonsafety-related systems and structures that met the 10 CFR 54.4(a)(2) scoping criteria. In the LRA, the applicant stated that the safety classification rules in approved plant procedures allowed identification of systems which included components that were credited for HELB, internal flooding, external flooding, internal missiles, load handling, and alternate/backup systems, or were credited in mitigating licensing-basis events.

The applicant augmented the preliminary list of nonsafety-related SCs obtained from the CMIS database by evaluating nonsafety-related SSCs for failure modes and effects or spatial interactions not explicitly functionally described in the plant CLB. This phase also included field verifications of plant areas containing safety-related equipment. In Section 2.1.5.3 of the LRA, the applicant noted that the pressure boundary aspects of nonsafety-related piping whose failure could affect a safety function would be addressed by the plant walkdown portion of the non safety-related equipment scoping. Although the applicant's scoping procedure, EP-3-S-0713, did not include specific requirements for performing field walkdowns, engineering guideline EG-021, Attachment A, Section 1.1.1.3 stated that field verifications must be performed to ascertain if any systems or system piping segments not already included within the scope of license renewal were present in areas containing safety-related equipment. The staff noted that the applicant did not use formalized procedures to control the performance of the field verifications. However, during the audit, the applicant stated that knowledgeable members of the Ginna LRA project team participated in the performance and review of the plant walkdowns. Therefore, based on discussions with the applicant related to the performance of the plant walkdowns and a sampling review of walkdown results, the staff concluded that the plant walkdowns were adequately controlled to support the scoping methodology.

During the scoping and screening audit, the applicant noted that the CLB included alternate coping strategies to mitigate the loss of safety-related function due to the failure of certain non safety-related equipment. In particular, the applicant noted that NUREG-0821, "Integrated Plant Safety Assessment, Systematic Evaluation Program, R.E. Ginna Nuclear Power Plant," documented the licensing basis for some modifications or strategies used to cope with the loss of safety-related SSCs from a variety of events. Where modifications alone were not sufficient to prevent the loss of a safety function due to a failure of nonsafety-related equipment, the applicant stated that the CLB permitted alternate or backup equipment to be credited to achieve safe shutdown.

During discussions, the applicant identified that the failure of the heating steam boiler in the screenhouse was an example in which an alternate system was credited. In this case, a failure of the nonsafety-related screenhouse steam heating boiler could result in loss of all redundant trains of service water. Consequently, the licensee installed an alternate service water supply to the emergency diesel generators to cope with this failure. Based on the availability of the alternate service water supply to the diesel generators (which was considered to be within the scope of license renewal), the applicant concluded that the portions of the steam heating system in the screenhouse that could result in the failure of the safety-related service water system pumps were not considered to be within the scope of license renewal. The applicant noted that the alternate service water supply to the diesel generators was intended to mitigate a loss of service water event due to a heating steam failure, but did not provide all the safety-related functions normally provided by the service water system.

The staff determined that the applicant did not consider the potential failure of the non safety-related steam heating boiler during other design-basis events, such as loss-of-coolant accidents, during the scoping process. Because the staff concluded that failure of the screenhouse steam heating boiler could result in loss of certain safety-related service water system intended functions, the staff questioned the basis for excluding this screenhouse steam heating boiler from the scope of license renewal.

As part of the discussion of the 10 CFR 54.4(a)(2) issues, the staff described its interim guidelines on the subject. In letters dated December 3, 2001, and March 15, 2002, the NRC issued a staff position to the NEI which described areas to be considered and options it expects licensees to use to determine what SSCs meet the 10 CFR 54.4(a)(2) criteria (i.e., "all non safety-related SSCs whose failure could prevent satisfactory accomplishment of any safety-related functions identified in paragraphs (a)(1)(i),(ii),(iii) of this section"). The December 3, 2001, letter (ADAMS accession number ML 013380013) provided specific examples of operating experience which identified pipe failure events (summarized in Information Notice (IN) 2001-09, "Main Feedwater System Degradation in Safety-Related ASME Code Class 2 Piping Inside the Containment of a Pressurized Water Reactor") and the approaches the NRC considers acceptable to determine which piping systems should be included in scope based on the 10 CFR 54.4(a)(2) criteria. The March 15, 2002, letter (ADAMS accession ML 020770026) further described the staff's expectations for the evaluation of nonpiping SSCs to determine which additional nonsafety-related SSCs are within scope. The position states that applicants should not consider hypothetical failures, but rather should base their evaluation on the plant's CLB, engineering judgment and analyses, and relevant operating experience. The paper further describes operating experience as all documented plant-specific and industry-wide experience which can be used to determine the plausibility of a failure. Documentation would include NRC generic communications and event reports, plant-specific condition reports, industry reports such as significant operational event reports (SOERs), and engineering evaluations.

Based on the 10 CFR 54.4(a)(2) staff position letters, the staff identified two specific areas for which additional information was required to complete the review of scoping pursuant to 10 CFR 54.4(a)(2). By letter dated March 21, 2003, the staff requested the following additional information from the applicant in RAI 2.1-4:

- Based on the aforementioned information regarding the scoping of heating steam system components in the vicinity of the service water pumps, and the results of the scoping and screening methodology audit interactions with the staff, the applicant was requested to describe any additional scoping evaluations performed to address the 10 CFR 54.4(a)(2) criteria. In particular, the staff noted the failure to consider the screenhouse steam heating boiler to be within the scope of license renewal even though an age-related failure of the boiler could result in the loss of a safety-related intended function. The staff requested that the applicant list any additional SSCs included within scope as a result of these efforts, and list those SCs for which AMRs were required.

- Consistent with the staff position described in the March 15, 2002, letter, the applicant was requested to describe the scoping methodology implemented for the evaluation of the 10 CFR 54.4(a)(2) criteria as it relates to the non-fluid-filled SSCs of interest. The staff determined that the LRA did not describe the scope and depth of the operating experience review conducted for non-fluid-filled systems. The staff requested that the applicant indicate the non-fluid-filled SSCs evaluated and describe the site and industry operating experience relied on to determine the potential for failures of such non-fluid-filled SSCs which could impact safety-related SSCs within scope.

By letter dated May 13, 2003, the applicant provided a response to the staff's RAI. In that response, the applicant stated, in part, that it had reviewed its 10 CFR 54.4(a)(2) evaluation and concluded that additional nonsafety-related SSCs, including the block walls in the intermediate building and the steam heating system in the screenhouse (including the boiler), met the criteria for 10 CFR 54.4(a)(2) inclusion. The applicant noted that the block walls are already addressed by an aging management program (AMP), because they are included in the scope of license renewal under 10 CFR 54.4(a)(3) for fire protection. The steam heating system is already within the scope of license renewal. As a result of this RAI, the applicant stated that the house heating boiler and associated components located in the screenhouse have been included as components requiring AMR. They will be managed by the Periodic Surveillance and Preventive Maintenance Program described in B2.1.23 of the LRA. A review of the AMP for these SSCs is included in Section 3.0.3.8 of this SER.

Additionally, the applicant described the evaluation of non-fluid-filled systems in its letter dated May 13, 2003. These evaluations were performed in the same manner as fluid-filled system 10 CFR 54.4(a)(2) evaluations, as described in Sections 2.1.5.2 through 2.1.5.4 of the LRA. The affected systems are containment ventilation, essential ventilation, nonessential ventilation, and radiation monitoring. The equipment in scope of 10 CFR 54.4(a)(2) is described in each of these sections within the LRA. The applicant noted that there is no plant-specific operating experience that would indicate potential failure modes of these systems affecting safety-related SSCs; however, supports and hangers are in the scope of license renewal as a Component Supports Commodity Group. As noted in that section, "all supports for any equipment contained within a safety-related structure, regardless of the equipment's seismic classification, shall be considered in-scope to license renewal unless a support is specifically excepted and that exception documented."

The staff has reviewed the additional information provided by the applicant regarding expansion of the scope of SSCs to include the steam heating system house heating boiler and associated components located in the screenhouse and the evaluation of non-fluid-filled systems for potential interaction with safety-related SSCs. On the basis of the additional information supplied by the applicant, including the expansion of the systems within the scope of license renewal and the addition of new portions of systems within scope as a result of the revised methodology, determination of the credible failures which could impact the ability of safety-related SSCs from performing their intended functions, evaluation of relevant operating experience, incorporation of identified nonsafety-related SSCs into the applicant's AMPs, and the results of NRC inspection and audit activities, the staff concludes that the applicant has supplied sufficient information to demonstrate that all SSCs that meet the 10 CFR 54.4(a)(2) scoping requirements have been identified as being within the scope of license renewal. Therefore, RAI 2.1-4 is considered resolved.

On the basis of this sample review, discussions with the applicant, and evaluation of the applicant's responses to the staff's RAIs, the staff determined that the applicant's methodology for identifying systems and structures meeting the scoping criteria of 10 CFR 54.4(a)(2) was adequate.

2.1.3.1.2.3 <u>Application of the Scoping Criteria in 10 CFR 54.4(a)(3)</u>. As required by 10 CFR 54.4(a)(3), the applicant must consider all SSCs relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), and station blackout (10 CFR 50.63) to be within the scope of the license renewal.

Section 5.1.4 of engineering procedure EP-3-S-0713 contained guidance for the scoping of the SSCs relied upon for these regulated events. The applicant identified SSCs within the scope of 10 CFR 54.4(a)(3) by performing reviews of associated plant documents. The specific documentation referenced in EP-3-S-0713 included the following:

- fire protection virtual design-basis document

- Appendix R analysis
- listing of 10 CFR 50.49 equipment contained in IP-EQP-1
- anticipated transients with scram design evaluations
- station blackout coping study contained in EWR-4520

The staff also noted that the safety classification program included specific rules associated with these regulated events. For example, the applicant's IP-QAP-1 safety classification rules included the following functions:

- fire detection, suppression, principal barriers, and mitigation systems and components used to protect safety-related or safe shutdown equipment

- system/components required to respond to or mitigate anticipated transients without scram in accordance with 10 CFR 50.62 requirements

- systems or components whose specific function was to ensure alternate shutdown capability and were subject to the requirements of 10 CFR 50, Appendix R

- systems or components required to respond to or mitigate the consequences of station blackout in accordance with NUMARC 87-00 and 10 CFR 50.63 including the committed to portions of RG 1.155

In addition, the applicant relied on the station EQ master list for the scoping of environmentally qualified equipment pursuant to the 10 CFR 54.4(a)(3) requirements.

As described in Section 2.1.3.1.1 of this SER, the staff evaluated the applicant's safety classification rules and the additional information requested relative to the use of the IP-QAP-1 safety classification rules for identifying systems and structures meeting the scoping criteria of 10 CFR 54.4(a), and determined that the rules adequately bounded the license renewal intended functions described in 10 CFR 54.4(a)(3).

As part of the review of the applicant's scoping methodology, the staff reviewed a sample of the license renewal database 10 CFR 54.4(a)(3) scoping results and a sample of the analyses and documentation to support these reviews. The staff also discussed the methodology and results with the applicant's personnel responsible for these evaluations. The staff verified that the applicant had identified and used pertinent engineering and licensing information to determine the SSCs required to be in scope in accordance with the 10 CFR 54.4(a)(3) criteria. Based on this sampling review, discussions with the applicant, and review of the additional information provided by the applicant in response to the staff's RAI, the staff determined that the applicant's methodology for identifying systems and structures meeting the scoping criteria of 10 CFR 54.4(a)(3) was adequate.

2.1.3.1.3 Plant-Level Scoping of Systems and Structures

Procedure EP-3-S-0713 outlined the following methodology for identifying systems and structures within the scope of license renewal. Initially, the applicant compiled a complete listing of functions performed by each plant system and structure. The applicant then compared system and structure functions to the 10 CFR 54.4(a) license renewal scoping criteria to identify those systems and structures with license renewal intended functions and, for those systems and structures with license renewal intended functions, the applicant determined the system and structure evaluation boundaries. In order to assure that all components required to support system intended functions were considered during subsequent SC-level scoping, Section 5.1.5.c of EP-3-S-0713 required an engineering cross-discipline review of boundary information to ensure that components at evaluation boundaries were not excluded from the review process.

The applicant developed license renewal implementation procedures to provide guidance in completing each of these system and structure scoping tasks. The methodology used in identifying systems and structures with license renewal specific intended functions is discussed in the following sections.

2.1.3.1.4 Component-Level Scoping

After the applicant identified the intended functions of systems or structures within the scope of license renewal, a review was performed to determine which components of each in-scope system and structure supported license renewal intended functions. The components that supported intended functions were considered to be within the scope of license renewal and screened to determine if an AMR was required. The applicant considered three component classification types during this stage of the scoping methodology—mechanical, civil and structural, and electrical. The scoping methodology for each of these component classifications is discussed below.

2.1.3.1.4.1 Mechanical Component Scoping. To support component-level scoping, the applicant identified license renewal scoping evaluation boundaries for in-scope mechanical systems utilizing P&IDs to identify functional and pressure boundaries. The applicant stated that all safety-related pressure boundaries were identified on the plant P&IDs. Additionally, Section 5.1.5.a.3 of EP-3-S-0713 specified that all interfacing pressure boundaries, such as branch lines and instrument lines for the required flow paths, must also be identified within scope unless analysis or calculation demonstrates that loss of the branch line or instrument line pressure boundary will not affect performance of the system intended function. In Section 2.1.5.3 of the LRA, the applicant stated that for interfaces between safety-related and nonsafety-related piping, the license renewal scoping boundary extended to the weld after the first seismic support beyond the class change depicted on the plant P&ID.

The applicant generated an initial listing of components within the scope of license renewal by populating the license renewal database for each in-scope system with system components as identified in the plant CMIS database. For components not uniquely identified in the plant electronic databases, such as structural components and piping, the applicant created component identifiers in the license renewal database for the purposes of license renewal scoping and screening. After the licensee initially populated the license renewal database with system and structural components, the consistency and accuracy of the component scoping was verified in accordance with engineering guideline EG-012, “Scoping and Screening and

Mechanical AMRs." The EG-012 review methodology included use of P&IDs to verify system boundaries and to verify that components supporting an intended function were within the scope of license renewal. In some cases, the applicant migrated components within the scope of license renewal to a different parent system or commodity group. In Section 2.1.3 of the LRA, the applicant stated that components within the scope of license renewal were moved from the original parent system in two specific cases:

(1) when the only in-scope portion of the system was comprised of components that received a commodity group evaluation

(2) when the only in-scope portion of the system was comprised of components that acted as containment isolation boundaries

During the audit, the applicant also stated that all reactor coolant pressure boundary components were moved to the reactor coolant system regardless of their initial parent system. The staff reviewed a sampling of components that had been migrated to a different parent system and determined that for all cases reviewed, the applicant appropriately scoped the migrated component. As part of the review of the applicant's scoping methodology, the staff reviewed a sample of the license renewal database scoping results for mechanical systems. Based on this sampling review and discussions with the applicant, the staff determined that the applicant's methodology for identifying mechanical system SCs within the scope of license renewal was adequate.

2.1.3.1.4.2 Structural Component Scoping. Section 5.2 of EP-3-S-0713 included general guidance applicable to structural and civil component scoping. The applicant stated civil and structural scoping plant walkdowns were conducted by contractor personnel. Although there was not a formal site-specific training or qualification program to support these plant walkdowns, the applicant stated that on-the-job training was provided to the contractor personnel performing the walkdowns. Specifically, the applicant reviewed the results of preliminary walkdowns and provided feedback and guidance to contractor personnel. This process was repeated until the applicant determined that contractor personnel were performing adequate civil and structural walkdowns. The applicant stated that the walkdown results were monitored and reviewed by Ginna LRA project personnel knowledgeable of license renewal requirements.

Based on discussions with the applicant and review of plant procedures, the staff determined that the structural and civil component scoping methodology used by the applicant was consistent with the process described in Section 2.1.7.2 of the LRA. Specifically, the structural scoping determinations were made based on a review of the CLB, plant drawings, CMIS data, and plant walkdowns. For components not uniquely identified in the plant electronic CMIS database, the applicant created component identifiers in the license renewal database for the purposes of license renewal scoping and screening. The staff reviewed a sampling of structural and civil scoping results and determined that, for the items reviewed, the scoping results appeared to be reasonable. On the basis of the above evaluation, the staff determined that the applicant's structural and civil component scoping methodology was adequate.

2.1.3.1.4.3 Electrical and Instrumentation and Controls Component Scoping. Engineering procedure EP-3-S-0718, “Electrical and I&C Integrated Plant Assessment Documents for License Renewal,” provided procedural guidance for the conduct of electrical component scoping. The applicant stated that the plant spaces approach was used to facilitate electrical component scoping and screening. Using this approach, the applicant initially assumed that all electrical and I&C components were within the scope of license renewal.

The applicant’s methodology allowed component scoping reviews to limit the number of components within a commodity group for which aging management activities were required. Section 5.34 of EP-3-S-0718 provided guidance for determining if a specific component could be scoped out of license renewal. This guidance included an evaluation of component functions against the scoping criteria of 10 CFR 54.4(a) when assessing if an electrical component had a license renewal intended function. Additionally, Attachment 5 to EP-3-S-0718 stated that consideration shall be given to the guidance provided in NUREG-1800 relative to electrical and I&C scoping determinations.

The staff reviewed a sampling of electrical and I&C system scoping results and determined that, for the items reviewed, the scoping results appeared to be reasonable. Because the applicant’s electrical spaces approach integrated the scoping and screening phases of the methodology, additional evaluation of this methodology is documented in Section 2.1.3.2.3 below.

2.1.3.1.4.4 Scoping Conclusions. The staff reviewed the scoping implementation procedures and a selected sample of the system scoping reports to ensure consistent application of the applicant’s scoping methodology. The staff noted that the sample reports reviewed were developed in accordance with the administrative controls governing the process and were consistent in level of detail and presentation. The staff further reviewed a sample of the license renewal drawings and system scoping results reports to ensure that the individual components identified in the system scoping results reports were reflected appropriately on the drawings. On the basis of the evaluation described above, including evaluation of the applicant’s responses to the staff’s RAIs, the staff determined that the scoping methodology was consistent with the requirements of the Rule, and that the scoping methodology is capable of identifying SSCs that meet the criteria of 10 CFR 54.4(a).

2.1.3.2 Screening Methodology

The staff reviewed the screening methodology used by the applicant to determine if mechanical, structural, and electrical components within the scope of license renewal would be subject to further aging management evaluation. The applicant described its screening process in Section 2.1.5 of the LRA. In general, the applicant’s screening approach consisted of evaluations to determine which in-scope SCs were passive and long-lived. Passive, long-lived SCs were then subject to further AMR.

The staff evaluated the applicant’s screening methodology against the criteria contained in 10 CFR 54.21(a)(1) and (a)(2) using the review guidance contained in NUREG-1800, Section 2.1.3.2, “Screening.” As 10 CFR 54.21(a)(1) states, the applicant’s integrated plant assessment must identify and list those SCs subject to an AMR. Further, 10 CFR 54.21(a)(1) requires that SCs subject to an AMR shall encompass those SCs that (1) perform an intended function, as described in 10 CFR 54.4, without moving parts or a change in configuration or properties, and (2) are not subject to replacement based on a qualified life or specified time period. Pursuant to 10 CFR 54.21(a)(2), the applicant must describe and justify the methods used to meet the requirements of 10 CFR 54.21(a)(1).

During the methodology audit, the applicant provided the staff with a detailed discussion of the processes used for each discipline and provided technical reports that described the screening methodology, as well as a sample of the screening results reports for a selected group of safety-related and nonsafety-related systems. The applicant's screening process followed the guidance provided in NEI 95-10 and consisted of the following three activities:

(1) review of system and structure intended functions

(2) identification of the components that support system or structure intended functions

(3) identification of long-lived, passive components that support a system or structure intended function and are therefore subject to an AMR

These major activities provided a mechanism to verify that system intended functions, based on detailed system design documentation, were captured adequately, and that the components selected for further review supported those intended functions. The results of the screening review for each system and structure were documented in the license renewal database and the associated scoping/screening report, in accordance with EP-3-S-0713. Screening methodologies unique to the mechanical, structural, and electrical reviews are discussed below.

2.1.3.2.1 Mechanical Component Screening

The staff reviewed the methodology used by the applicant to identify and list the mechanical components subject to an AMR, as well as the applicant's technical justification for this methodology. The staff also examined the applicant's results from the implementation of this methodology by reviewing an overview of the mechanical systems identified as being within the scope, a sample of evaluation boundaries drawn within those systems, the resulting components determined to be within the scope of the Rule, the corresponding component-level intended functions, and the resulting list of mechanical components subject to an AMR.

The applicant provided procedural guidance for the conduct of mechanical component screening in procedure EP-3-S-0713 and EG-012. Section 5.2.2.b of EP-3-S-0713 referenced the use of Appendix B to NEI 95-10 when determining when a component should be considered active or passive. Additionally, the applicant determined which components were subject to replacement based on a qualified life or specified time period and therefore considered not subject to an AMR. For those passive components subject to an AMR, the applicant identified component intended functions.

As described in a May 1, 2002, License Renewal Issue letter (ML 021220429), the staff expects applicants to identify active component housings which require an AMR. This determination should consider whether the failure of the housing would result in failure of the associated active component to perform its function and whether the housing meets the long-lived and passive criteria as defined in the Rule. In Section 2.1.6 of the LRA, the applicant described the screening methodology used for the housings of active components. The applicant considered fan housings and fire damper housings to be within scope and subject to an AMR. Therefore, the staff determined that the applicant's screening methodology for mechanical equipment, including the housings of active equipment, was adequate.

2.1.3.2.2 Structural Component Screening

The staff reviewed the methodology for identifying structural components subject to an AMR, as well as the applicant's technical justification for this methodology. The staff also examined the applicant's results from the structural screening methodology by reviewing the structural components identified as being within the scope of license renewal, the corresponding structural component intended functions, and the resulting list of structural components subject to an AMR.

General guidance for the conduct of structural screening was provided in Section 5.2 of EP-3-S-0713. The applicant identified structural components within the license renewal evaluation boundaries of each plant-level structure. For components not uniquely identified in the CMIS database, the applicant created component identifiers in the license renewal database for the purposes of scoping and screening. The applicant also placed certain structural components into a component support commodity group, which was then evaluated as a separate in-scope plant-level system. As described in Section 5.2.2 of EP-3-S-0713, all structural components within license renewal structural scoping evaluation boundaries, with the exception of snubbers, were assumed to be long-lived and passive, and thus subject to an AMR. On this basis, the staff determined that the applicant's screening methodology for civil and structural equipment was adequate.

2.1.3.2.3 Electrical and Instrumentation and Controls Component Screening

After identifying the SSCs within the scope of license renewal, the staff reviewed the applicant's screening review to determine which electrical components would be subject to an AMR. The applicant used a plant spaces approach for electrical and I&C scoping which screened components on a plant-wide basis rather than on a system basis. In Section 2.5 of the LRA, the applicant identified the following commodity groups used for electrical and I&C screening:

- medium-voltage insulated cables and connections
- low-voltage insulated cables and connections
- electrical portions of electrical and I&C penetration assemblies
- electrical phase bus
- switchyard bus
- transmission conductors
- uninsulated ground conductors
- high-voltage insulators

The applicant stated in Section 2.1.7.4, “Electrical and I&C Systems,” of the LRA, that a review of the UFSAR, the plant’s database, and DBDs did not identify the need to add any additional commodity groups. The plant was segregated into areas where common, bounding environmental parameters could be assigned. The applicant then identified electrical commodity groups that were installed in the identified plant space and determined which group had the limiting aging characteristics for the plant space. The limiting commodity group was then subject to an AMR. Based on the information presented in the LRA, the staff questioned if the electrical and I&C screening methodology could result in the failure to subject in-scope commodity groups, that were not the most age-limited, to an AMR. In RAI 2.1-3, dated March 21, 2003, the staff requested that the applicant provide additional information regarding the screening methodology treatment of electrical and I&C system commodity groups to demonstrate that all in-scope commodity groups are subject to an AMR.

On May 23, 2003, the applicant responded to the staff’s RAI by providing additional information regarding the screening methodology treatment of electrical and I&C system commodity groups to demonstrate that all in-scope commodity groups are subject to an AMR. The applicant stated that Section 2.1.7.4 of the LRA describes a process of using a preliminary analysis to avoid inefficiencies in the scoping and screening process and focuses on the limiting (bounding) materials of construction and limiting (bounding) environmental conditions. The analysis was used to avoid an exclusionary scoping review for those commodity groups and components that have no aging effects requiring management, or are intended to be included in an AMR program due to regulatory precedent. As stated in the LRA, all passive, long-lived electrical and I&C commodity groups were initially considered subject to an AMR, and the conclusions of the preliminary analysis did not change this initial position. The applicant further stated that only commodity-specific, or component-specific exclusion scoping, are used to identify passive, long-lived components that are not subject to an AMR.

Furthermore, the staff has confidence that the preliminary analysis performed by the applicant, which focused on the bounding materials of construction and environmental conditions, should help to avoid inefficiencies in the scoping and screening process and does not change the position in the LRA that all passive, long-lived electrical and I&C commodity groups are considered subject to an AMR. Therefore, the staff considers RAI 2.1-3 resolved.

Based on the information provided by the applicant in the LRA, the staff’s audit of the applicant’s scoping and screening methodology, and the additional information provided by the applicant in response to the staff’s RAI, the staff concluded that the applicant’s screening methodology for electrical and I&C equipment is acceptable.

2.1.3.2.4 Screening Conclusions

The staff reviewed the screening implementation procedures and a selected sample of the system screening reports to ensure consistent application of the applicant’s screening methodology. The staff noted that the sample reports reviewed were developed in accordance with the administrative controls governing the process and were consistent in level of detail and presentation. The staff further reviewed a sample of the license renewal drawing and system screening table results to ensure that the individual components identified in the system screening tables were reflected appropriately on the drawings. For those components identified in the screening table and not requiring an AMR, the individual screening report provided an explanation for the component exclusion from an AMR. The staff reviewed a sample of these explanations and found that they were consistent with the guidance and provided adequate justification for the determination made. The staff did not observe any discrepancies between the sample tables and drawings evaluated. On the basis of the evaluation described above, the staff determined that the screening methodology was consistent with the requirements of the Rule, and that the screening methodology will identify SCs that meet the screening criteria of 10 CFR 54.21(a)(1).

2.1.4 Evaluation Findings

The staff's review of the information presented in Section 2.1 of the LRA, the supporting information in the implementing guidelines and engineering procedures, the information presented during the scoping and screening audit, the NRC scoping inspection, and the applicant's responses to the staff's RAIs formed the basis of the staff's safety determination. The staff verified that the applicant's scoping and screening methodology, including its supplemental 10 CFR 54.4(a)(2) review which brought additional nonsafety-related components into the scope of license renewal, was consistent with the requirements of the Rule and the staff's position on the treatment of nonsafety-related SSCs. On the basis of this review, the staff concludes that there is reasonable assurance that the applicant's methodology for identifying the SSCs within the scope of license renewal and the SCs requiring an AMR is consistent with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.2 <u>Plant-Level Scoping Results</u>

2.2.1 Summary of Technical Information in the Application

This section addresses the plant-level scoping results for license renewal. Per 10 CFR 54.21(a)(1), the applicant is required to identify and list SCs subject to an AMR. These are passive and long-lived SCs that are within the scope of license renewal.

In LRA Table 2.2-1, the applicant provided a list of the plant systems and structures, identifying those that are within the scope of license renewal. The Rule does not require the identification of all plant systems and structures. However, providing such a list allows for a more efficient staff review. On the basis of design-basis events considered in the plant's (CLB and other CLB information relating to nonsafety-related systems and structures and certain regulated events, the applicant identified those plant-level systems and structures within the scope of license renewal, as defined in 10 CFR 54.4(a). To verify that the applicant has properly implemented its methodology, the staff focuses its review on the implementation results to confirm that there is no omission of plant-level systems and structures within the scope of license renewal.

2.2.2 Staff Evaluation

The SOC for the license renewal rule (60 FR 22478) indicates that an applicant has the flexibility to determine the methodology it will use to identify the set of SCs for which the scoping and screening process specified in 10 CFR 54.21(a)(1) will be performed. Accordingly, the staff focused its review on verifying that the implementation of the applicant's methodology, discussed in Section 2.1 of this SER, did not result in the omission of SCs that perform an intended function that meets the 10 CFR 54.4 scoping criteria. In LRA Table 2.2-1, the applicant listed the Ginna SSCs within the scope of license renewal. The staff reviewed this list to determine whether any SSCs that met the 10 CFR 54.4 scoping criteria had been omitted.

The staff performed the following evaluations:

- Ginna was constructed before the adoption of the Standard Review Plan (NUREG-0800). As described in more detail in the following sections of this SER, the staff reviewed the plant's CLB as documented in the Ginna UFSAR, the final report from the Ginna integrated plant safety assessment study performed as part of the Systematic Evaluation Program (NUREG-0821), and related documents and drawings. All of the systems and structures identified in these documents and drawings were reviewed to confirm that the applicant did not omit systems or structures from within the scope of license renewal that meet the 10 CFR 54.4 scoping criteria.

- To determine whether the applicant had properly identified the components and commodity groups subject to an AMR that make up the systems and structures identified above, the staff reviewed design documents and drawings for the systems and structures within the scope of license renewal to verify that the applicant did not omit components that meet the criteria in 10 CFR 54.21(a)(1).

In the comments column of LRA Table 2.2-1, the applicant stated that certain components from out-of-scope systems were evaluated as part of other systems within the scope of license renewal. This practice is acceptable as long as the components so treated are clearly identified in a manner traceable to the CLB documentation. In part, 10 CFR 54.21(a)(1) states that components and their intended functions that meet the scoping criteria of 10 CFR 54.4(a) and are subject to an AMR must be identified so that their aging effects can be adequately managed consistent with Ginna's CLB. In order to confirm that SSCs with intended functions described in the UFSAR using traditional (i.e., CLB) nomenclature have been captured in the license renewal process, the staff needs to identify components from out-of-scope systems that were evaluated as part of the systems within the scope of license renewal in the LRA and the scoping boundary drawings.

By letter dated March 21, 2003, the staff requested that the applicant identify the components from the out-of-scope systems (identified below) in the tables contained in LRA Section 2.3 (RAI 2.2-1):

- circulating water
- plant air
- plant sampling
- fuel handling
- nonessential ventilation

Also, RAI 2.2-1 requested that the applicant identify the components of these systems that perform intended functions that are evaluated with other systems, the intended functions they perform, and if they are subject to an AMR.

By letter dated June 16, 2003, the applicant responded that the philosophy of evaluating specific components within other systems is provided in LRA Section 2.1.3. In the cases of plant air and plant sampling systems, the containment isolation portions of the systems were grouped in accordance with the SRP-LR, Section 2.3.1 and Table 2.1-2, as well as NUREG-1801, Chapter V, Section C. For nonessential ventilation, those portions of the system that act as fire barriers have been evaluated as a commodity, again in accordance with the SRP. Section 2.1.3 of the LRA, “System Function Determination,” states, system scoping must identify all license renewal functions associated with components contained within a system. Generally, within the license renewal system boundary, if the system under review contains any components that meet the license renewal scoping criteria detailed in 10 CFR 54.4(a), the entire system is considered in scope and that system moves forward to the license renewal screening process.

There are two specific exceptions to this dictate:

(1) When the only in-scope portion of the system comprises components that will receive a commodity group evaluation (e.g., fire barriers, equipment supports, etc.). In this case, it is appropriate to identify the system or structure as not being within the scope of license renewal; however, the basis for that determination must be clearly identified.

    Example: The nonessential ventilation systems contain components that act as fire barriers (fire dampers). Within the system evaluation boundary, no other functions performed by the system are license renewal intended functions. Therefore, this method of evaluation of the system components that perform the fire barrier function within the fire barrier commodity group results in designation of the nonessential ventilation systems as not being within the scope of license renewal.

(2) When the only in-scope portion of the system comprises components that act as containment isolation boundaries. In that case, it is appropriate to identify the system as not being within the scope of license renewal so long as the components that perform the isolation boundary function are evaluated within the containment isolation boundary system.

    Example: The plant sampling system contains components that act as containment isolation boundaries (e.g., valves or pipes). Within the system evaluation boundary, no components, other than those that perform the isolation function, perform any additional license renewal intended functions. Therefore, this method of evaluation of the system components that perform the containment isolation boundary function within the containment isolation system results in the designation of plant sampling as not being within the scope of license renewal.

Components of the specific systems addressed in RAI 2.2-1 are listed below:

- For plant air, the affected components are addressed in LRA Section 2.3.2.5, "Containment Isolation Components." The components are shown between the safety class 2 flags bounding the containment penetrations on drawings 33013-1882-LR; 33013-1884,1-LR; 33013-1884,2-LR; 33013-1886,2-LR; and 33013-1893-LR (on this drawing, the appropriate components are not highlighted; this is a drafting error). The affected components are pipe, valve bodies, and flanges as listed in Table 2.3.2-5.

- For plant sampling, the affected components are addressed in LRA Section 2.3.2.5, "Containment Isolation Components." The components are shown between the safety class 2 flags bounding the containment penetrations on drawings 33013-1278,1-LR and 33013-1279-LR. The affected components are pipe, valve bodies, delay coil, and flanges as listed in Table 2.3.2-5.

- For fuel handling, the affected components are addressed in LRA Section 2.3.2.5, "Containment Isolation Components." The components are shown between the safety class 2 flags bounding the containment penetration on drawing 33103-1248-LR and are associated with the fuel transfer slot containment penetration. The affected components are pipe, valve bodies, and flanges as listed in Table 2.3.2-5.

- For nonessential ventilation systems, the affected components are addressed in LRA Section 2.3.3.6, "Fire Protection." As noted in the system description, fire dampers are treated within the fire protection commodity group. The affected dampers are designated with an "f" adjacent to the damper identification number associated with both the essential and nonessential ventilation system (LRA Sections 2.3.3.10 and 2.3.3.19). These devices are not highlighted on the drawings (unless they act with a pressure boundary function to support the host systems ductwork intended function) because they are treated as a commodity group. Specific damper identification numbers are called out in the Fire Protection Program implementing procedures. The affected components are listed under the component group "structure" in Table 2.3.3-6 with the link to Table 3.4-,1 line 19, being appropriate to fire damper frame housings.

- The circulating water system and the service water system share certain components within the scope of license renewal. In the application, the emergency intake from the discharge canal as well as the combined service water/circulating water discharge piping is included in the service water system boundary. The affected components are pipe and valve bodies as listed in Table 2.3.3-5.

The staff finds the applicant's response to RAI 2.2-1, relating to the circulating water, plant sampling, plant air, fuel handling, and nonessential ventilation systems, to be acceptable on the basis that it confirmed the applicant's determination that these systems, with the evaluation boundaries specified in the LRA and delineated in the accompanying scoping boundary drawings, do not perform an intended function that meets the scoping criteria of 10 CFR 54.4(a). The applicant's RAI response clarified that certain fire dampers in the essential and nonessential ventilation systems were evaluated as commodities with the fire protection system and also confirmed that the specific components of the plant air, plant sampling, and fuel handling systems that the LRA identified as being evaluated with other systems were in fact included as components of the containment isolation system within the scope of license renewal.

2.2.3 Evaluation Findings

On the basis of this review, the staff concludes that there is reasonable assurance that the applicant has appropriately identified the systems and structures within the scope of license renewal in accordance with 10 CFR 54.4.

2.3 Scoping and Screening Results: Mechanical Systems

This section addresses the mechanical systems' scoping and screening results for license renewal. The mechanical systems consist of the following (the SER sections are also provided):

- reactor systems reactor coolant (Class 1) (2.3.1.1)
  reactor vessel (2.3.1.2)
  reactor vessel internals (2.3.1.3)
  pressurizer (2.3.1.4)
  steam generators (2.3.1.5)
  reactor coolant (non-Class 1) (2.3.1.6)

- engineered safety feature systems
  safety injection (2.3.2.1)
  containment spray (2.3.2.2)
  residual heat removal (2.3.2.3)
  containment hydrogen detectors and recombiners (2.3.2.4)
  containment isolation components (2.3.2.5)

- auxiliary systems
  chemical and volume control (2.3.3.1)
  component cooling water (2.3.3.2)
  spent fuel pool cooling and storage (2.3.3.3)
  waste disposal (2.3.3.4)
  service water (2.3.3.5)
  fire protection (2.3.3.6)
  heating steam (2.3.3.7)
  emergency power (2.3.3.8)
  containment ventilation (2.3.3.9)
  essential ventilation (2.3.3.10)
  cranes, hoists, and lifting devices (2.3.3.11)
  treated water (2.3.3.12)
  radiation monitoring—mechanical (2.3.3.13)
  circulating water (2.3.3.14)

chilled water (2.3.3.15)
fuel handling (2.3.3.16)
plant sampling (2.3.3.17)
plant air (2.3.3.18)
nonessential ventilation (2.3.3.19)
site service and facility support (2.3.3.20)

- steam and power conversion systems
  main and auxiliary steam (2.3.4.1)
  feedwater and condensate (2.3.4.2)
  auxiliary feedwater (2.3.4.3)
  turbine generator and supporting systems (2.3.4.4)

According to 10 CFR 54.21(a)(1), an applicant must identify and list SCs subject to an AMR. These are passive, long-lived SCs that are within the scope of license renewal. To verify that the applicant has properly implemented its methodology, the staff focuses its review on the implementation results. Such a focus allows the staff to confirm that there is no omission of mechanical system components that are subject to an AMR. If the review identifies no omission, the staff has the basis to find that there is reasonable assurance that the applicant has identified the mechanical system components that are subject to an AMR.

During its review, the staff determined that additional information was needed to clarify the information presented in certain tables in Section 2.3 of the LRA. By letter dated March 21, 2003, the staff requested that the applicant clarify the usage of system function code "S," which LRA Table 2.1-1 describes as indicating a "Special Capability Class Function" (RAI 2.3-1).

By letter dated May 16, 2003, the applicant clarified that the Ginna plant process for functionally based classifications was used in the development of the application. The "S" system function code broadly identifies a wide variety of components that are in the augmented quality assurance category. The basis for the augmented quality status is described in the applicant's component classification procedure IP-QAP-1 by rule 3.1.4.27, "Components or systems that do not perform a nuclear safety function, but are required to be operable by Ginna Station Technical Specification Limiting Conditions for Operation including the Technical Requirements Manual (TRM)." The "S" system function is generic and meant to prompt the reviewer to look further down the list for other codes which may indicate a license renewal intended function. The applicant's response to RAI 2.3-1 is acceptable to the staff on the basis that it clarifies that system function code "S" does not directly relate to a license renewal intended function.

By letter dated March 21, 2003, the staff requested that the applicant clarify whether the component group "pipe" includes all fittings, such as reducers, enlargers, flanges, and end caps, shown as part of a piping run on the license renewal boundary drawings and shown as being subject to an AMR on the license renewal system boundary drawings, but not specifically listed in the tables in LRA Section 2.3 (RAI 2.3-2). Some LRA tables have a component identified as "pipe" (for example, Table 2.3.2-2 for containment spray), while tables for other LRA sections have components identified as "piping and fittings."

By letter dated May 16, 2003, the applicant responded that the component group “pipe” includes all fittings, such as reducers, enlargers, flanges, and end caps, shown as part of a piping run on the license renewal boundary drawings. The staff considers the applicant’s response to RAI 2.3-2 to be acceptable on the basis that it clarifies that these pipe fittings are included in the scope of license renewal and are subject to an AMR.

By letter dated March 21, 2003, the staff asked the applicant to identify the standards that are relied upon for the replacement of consumable items such as O-rings and filters (RAI 2.3-3). By letter dated May 28, 2003, the applicant responded with the following information:

> The double O-ring seals used to provide containment isolation pressure boundaries are in the scope of the license renewal rule and are subject to AMR. Table 3.6-1, line number 6 of the LRA identifies these components and the programs that monitor their performance. These O-rings are replaced each time a flange is removed.
>
> The charcoal and HEPA filters are subject to the requirements of the plant Technical Specification Ventilation Filter Testing Program (TS 5.5.10). This program uses the standards endorsed by Regulatory Guide 1.52, Revision 2, as modified in the specification.
>
> The low and moderate efficiency (roughing) filters are subject of the requirements of the station periodic surveillance and preventive maintenance program which has repetitive tasks (reptasks) which require inspection of the filter condition on a frequency between 4 and 8 weeks, depending on the filter. These frequencies were established through years of operational experience and include consideration of physical location. When a filter shows signs of debris accumulation and fouling, it is replaced.

The staff considers the applicant’s response to RAI 2.3-3 to be acceptable on the basis that specific replacement criteria were provided for consumable items not subject to an AMR in accordance with the requirements of the Rule.

Because the review identified no omission, the staff has the basis to find that there is reasonable assurance that the applicant has identified the mechanical system components that are subject to an AMR.

2.3.1 Reactor Systems

In Section 2.3.1, “Reactor Coolant System,” of the Ginna LRA, RG&E (the applicant) described the SSCs of the reactor coolant system (RCS) that are subject to AMR for license renewal.

2.3.1.1 Reactor Coolant (Class 1)

2.3.1.1.1 Summary of Technical Information in the Application

As described in the LRA, the RCS transports the heat generated in the reactor core to secondary heat removal systems. The RCS also acts in conjunction with the fuel and the primary containment systems to provide defense in depth with respect to preventing fission products from escaping to the environment. Consequently, the RCS is associated with mitigating virtually all accidents, transients, and events.

The principal components of the RCS include the reactor vessel, pressurizer, steam generators, reactor coolant pumps, and the essential Class 1 piping and valves (including the regenerative and letdown heat exchangers). The RCS consists of two identical heat transfer loops connected in parallel to the reactor vessel. Each loop contains a circulating pump and a steam generator.

The AMR for the following system components was performed using the Westinghouse Commercial Atomic Power (WCAP) AMR and the corresponding applicant action item requirements detailed in the appropriate NRC SER :

- reactor vessel
- reactor vessel internals
- reactor coolant system Class 1
- reactor coolant system non-Class 1
- pressurizer
- steam generator

The fluid systems that interface with the RCS are plant sampling, waste disposal, residual heat removal, safety injection, chemical and volume control, and CCW.

The following are the RCS subsystems, whose descriptions are provided in the following sections:

- reactor vessel
- reactor vessel internals
- pressurizers
- steam generators

Additional details of the RCS are provided in Sections 5.1, 5.2, and 5.4 of the UFSAR.

The component groups for this system that require AMR are indicated in Table 2.3.1-1 of the LRA, along with each component group's passive functions and references to the corresponding AMR tables in Section 3 of the LRA. The component groups identified in the table include valves; reactor coolant pump (RCP) casing, main flange, and thermal barrier flange; heat exchanger tubing; orifices and reducers; piping and fittings; primary loop elbows; bolting for flanged piping joints, RCPs, and valve closures; and RCP lugs. The intended functions identified are pressure boundary, heat transfer, throttling, and mechanical closure integrity.

2.3.1.1.2 Staff Evaluation

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

The staff reviewed the relevant portions of the UFSAR for Ginna for the reactor coolant (Class 1) and associated pressure boundary components and compared the information in the UFSAR with the information in the LRA to identify those portions that the LRA did not identify as being within the scope of license renewal and subject to an AMR. The staff then reviewed the SCs that were identified as not being within the scope of license renewal to verify that these SCs do not have any of the intended functions delineated under 10 CFR 54.4(a). For those SCs that have applicable intended functions, the staff verified that they either perform these functions with moving parts or a change in configuration or properties, or that they are subject to replacement based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1).

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

After completing the initial review, the staff requested the applicant to provide additional information on the RCS (Class 1).

The pressurizer surge and spray nozzle thermal sleeves were not identified in the LRA (Table 2.3.1-4) as within the scope of license renewal. The staff understands that the intended function of the thermal sleeves is to provide thermal shielding to the nozzles (pressure boundary), and that the failure of the sleeves may prevent the nozzles from performing their pressure boundary function during the extended period of operation. As such, thermal sleeves meet the criteria identified in 10 CFR 54.4(a)(2) and, therefore, should be within the scope of license renewal. Furthermore, the Westinghouse Owners Group has proposed in topical report WCAP-14574-A, “License Renewal Evaluation: Aging Management Evaluation for Pressurizers,” and the staff has concurred, that the pressurizer surge and spray nozzle thermal sleeves are within the scope of license renewal. However, the staff also understands that an in-scope component may not require an AMR if a TLAA was performed for the component, and the result was found to be acceptable for the extended period of operation.

Based on the above, the staff requested the applicant in RAI 2.3.1-2 to provide the following additional information:

(a) On the basis of the reason cited above, include the pressurizer surge and spray nozzle thermal sleeves within scope or justify their omission.

(b) Respond to the following questions: Was a TLAA performed for the thermal sleeves as an integral part of the nozzles? If so, are the results of the TLAA also applicable to the sleeves (in addition to the nozzles), and are the results acceptable for the extended period of operation?

(c) If the answers to b. are not affirmative, submit an AMR for the thermal sleeves that are in-scope components, or justify why an AMR is not required.

(d) Identify any other thermal sleeves that perform thermal shielding function for pressure boundary components, such as the return line from the residual heat removal (RHR) loop, and the charging lines and the alternate charging line connections (refer to Ginna UFSAR

Section 5.4.3.1.1), which may have been excluded from the scope of license renewal. If any thermal sleeves are identified, justify their exclusion from the scope.

By letter dated May 13, 2003, the applicant responded point-by-point to these requests as follows:

> a. The pressurizer surge and spray nozzle thermal sleeves are already accounted for in the LRA. They are within the scope of the rule and are evaluated as part of the constituent component nozzle assemblies.
>
> b. The thermal sleeves are included within metal fatigue TLAA evaluations in LRA Section 4.3 and are accounted for in LRA Section B3.2, the Fatigue Monitoring Program. The TLAA evaluation includes the nozzles and sleeves, and the evaluation results indicate that the assemblies are acceptable for the period of extended operation, including accounting for the consequences of environmentally assisted fatigue.
>
> c. Because the response to b was affirmative, point c is not applicable.
>
> d. In addition to the pressurizer surge line and spray nozzles, the return line from the RHR loop, the charging and alternate charging lines, and the safety injection accumulator connections to the RCS all have nozzles containing thermal sleeves. These nozzles are within the scope of the LRA and have received TLAA evaluations. As with the pressurizer nozzles, aging effects for these components are managed within the Fatigue Monitoring Program. Additionally, the steam generator feedwater nozzles contain thermal sleeves. The steam generators were replaced in 1996, and these components did not require TLAA evaluation because an explicit fatigue analysis was performed according to the requirements of the American Society of Mechanical Engineers (ASME) Section III, Subsection NB-3600, for the 40-year design life of the steam generators. Therefore, these components do not require fatigue monitoring. They are, however, in scope to the Rule and subject to other aging management programs (AMPs) as identified in the LRA.

The staff did not identify any omissions.

2.3.1.1.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's response to the staff's RAI to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified those portions of the RCS (Class 1) and its associated (supporting) SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified those portions of the RCS (Class 1) and its associated (supporting) SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.1.2 Reactor Vessel

2.3.1.2.1 Summary of Technical Information in the Application

The Ginna Station reactor pressure vessel (RPV), as the principal component of the RCS, contains the heat-generating core and associated supports, controls and instrumentation, and coolant circulating channels. Primary outlet and inlet nozzles provide for the exit of heated coolant and its return to the RPV for recirculation through the core.

The Ginna Station RPV consists of a cylindrical shell with a hemispherical bottom head and a flanged and gasketed removable upper head. The RPV shell is fabricated from integral ring forgings joined by circumferential welds. The RPV contains the core, core support structures, rod control clusters, thermal shield or neutron shield panels, and other parts directly associated with the core. Inlet and outlet nozzles are located at an elevation between the head flange and the core. The body of the RPV is low-alloy carbon steel, and the inside surfaces in contact with coolant are clad with austenitic stainless steel to minimize corrosion. The RPV is supported by steel pads integral with the coolant nozzles. The pads rest on steel base plates atop a support structure attached to the concrete foundation.

Additional reactor vessel details are provided in Section 5.3 of the UFSAR.

The subcomponents of the reactor vessel that require AMR are indicated in Table 2.3.1-2 of the LRA along with each subcomponent's passive functions and references to the corresponding AMR tables in Section 3 of the LRA. The component groups identified in the table include control and drive mechanism rod travel housings, latch housing, and housing tubes (head adapters); vent pipe; closure head dome and flange; vessel flange; O-ring leak monitor tubes; upper shell; primary inlet and outlet nozzles; primary nozzle safe ends; intermediate shell (including circumferential weld); lower shell; core support lugs; bottom head torus; bottom head dome; instrumentation tubes and safe ends; bottom mounted instrument (BMI) guide tubes; seal table fittings; ventilation shroud support ring; closure studs, nuts, and washers; refueling seal ledge; and nozzle support pads.

The intended functions identified are pressure boundary, support of reactor vessel (RPV) internals, support of thimble tubes, structural support, and mechanical closure integrity.

2.3.1.2.2 Staff Evaluation

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

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

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

After completing the initial review, the staff requested the applicant to provide additional information on the RPV.

Borated water leakage through the pressure boundary in pressurized-water reactors (PWRs) and resulting borated-water-induced wastage of carbon steel is a potential aging degradation mechanism for the components. Reactor vessel head lifting lugs are considered to be components requiring aging management. However, if the components are currently covered under the Boric Acid Corrosion Program, then they may not require additional aging management. It appears that the subject components were not discussed in the LRA (Table 2.3.1-2), and, therefore, the staff requested the applicant in RAI 2.3.1-1 to verify whether the components are within the surveillance program and, if not, justify their omission.

By letter dated May 13, 2003, the applicant responded to the staff's RAI. The applicant clarified that the reactor vessel head lifting lugs are included in the LRA in Table 2.3.1-2, under the subcomponent "Closure Head Dome." Furthermore, the applicant confirmed that RPV head lifting lugs are included in the Boric Acid Corrosion Program, as are all carbon/low-alloy steel external surfaces in the RCS and that the AMP identified in LRA Table 3.2-1, line 26, will be applicable for the head lifting lugs.

The staff did not identify any omissions.

2.3.1.2.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's response to the staff's RAI to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified those portions of the RPV and its associated (supporting) SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified those portions of the RPV and its associated (supporting) SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.1.3 Reactor Vessel Internals

2.3.1.3.1 Summary of Technical Information in the Application

The Ginna Station reactor vessel internals (RVIs) consist of two basic assemblies.

(1) Upper internals assembly that is removed during each refueling operation to obtain access to the reactor core. The top of this assembly is clamped to a ledge below the vessel-head mating surface by the reactor vessel head. The core barrel fuel alignment pins of the lower internals assembly guides the bottom of the upper internals assembly.

(2) Lower internals assembly that can be removed, if desired, following a complete core unload. This assembly is clamped at the same ledge below the vessel head mating surface and closely guided at the bottom by radial/clevis assemblies.

Additional details of the RVI are provided in Section 3.9.5 and Section 4.2.1 of the Ginna UFSAR.

The subcomponents of the RVI that require AMR are indicated in Table 2.3.1-3 of the LRA along with each subcomponent's passive functions and references to the corresponding AMR tables in Section 3 of the LRA. The component groups identified in the table include lower core plate and fuel pins; lower support forging and columns; core barrel and flange; radial keys and clevis inserts; baffle and former assembly; core barrel outlet nozzle; secondary core support; diffuser plates; upper support plate assembly; upper core plate and fuel alignment pins; upper support columns; rod cluster control assembly (RCCA) guide tubes and flow downcomers; guide tube support pins; upper core plate alignment pins; hold down spring; head/vessel alignment pins; thermal shield and neutron panels; BMI columns and flux thimbles; head cooling spray nozzles; upper instrumentation column, conduit, and supports; bolting (upper support column, guide tube, and clevis insert); and bolting (lower support column, baffle/former, and barrel/former).

The intended functions identified are core support, flow distribution, guidance and support of RCCAs, vessel shielding, guidance and support of instrumentation, and guidance and support of thermocouples.

2.3.1.3.2 Staff Evaluation

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

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

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

The staff did not identify any omissions.

2.3.1.3.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's responses to the staff's RAI to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified those portions of the reactor vessel and its associated (supporting) SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified those portions of the reactor vessel and its associated (supporting) SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.1.4 Pressurizer

2.3.1.4.1 Summary of Technical Information in the Application

The Ginna pressurizer is part of the RCS and is located inside containment. The RCS pressure control consists of the pressurizer vessel equipped with electric heaters, safety valves, relief valves, pressurizer spray, interconnecting piping, and instrumentation. During operation, the pressurizer contains saturated water and steam maintained at the desired saturation temperature and pressure by the electric heaters and pressurizer spray. The chemical and volume control system (CVCS) maintains the desired water level in the pressurizer during steady-state operation by a pressurizer level control instrumentation system.

During normal operation, the external electrical network imposes load changes on the plant turbine generator. These load changes cause temperature changes in the RCS. Since the reactor rod control system, which controls the reactor coolant temperature, does not respond instantaneously during a load transient, the pressurizer pressure control system is designed to absorb the reactor coolant volume surges and limit pressure variations during the initial transient period prior to an effective response by the reactor rod control system.
The pressurizer performs the following functions:

- maintains the required reactor coolant pressure (pressure boundary function) during steady-state operation and normal heatup and cooldown

- limits pressure changes that are caused by reactor coolant thermal expansion and contraction during normal plant load changes and transients to an allowable range

Additional pressurizer details are provided in Section 5.4.7 of the Ginna UFSAR.

The subcomponents of the pressurizer that require AMR are indicated in Table 2.3.1-4 of the LRA along with each subcomponent's passive functions and references to the corresponding AMR tables in Section 3 of the LRA. The component groups identified in the table include lower head, surge nozzle, surge nozzle safe end, heater well and heater sheath, shell, instrument nozzles thermowells, upper head, spray nozzle and safe end, safety nozzle and safe end, relief nozzle and safe end, manway cover, support skirt and flange, and manway cover bolts.

The intended functions identified are pressure boundary, structural support, and mechanical closure integrity.

2.3.1.4.2 Staff Evaluation

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

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

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

After completing the initial review, the staff asked the applicant for additional information on the pressurizer surge and spray nozzle thermal sleeves (RAI 2.3.1-2). Section 2.3.1.1.2 of this SER discussed RAI 2.3.1-2 and the applicant's response.

The staff did not identify any omissions.

2.3.1.4.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's response to the staff's RAI to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified those portions of the pressurizer and its associated (supporting) SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified those portions of the pressurizer and its associated (supporting) SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.1.5 Steam Generators

2.3.1.5.1 Summary of Technical Information in the Application

The steam generators (SGs) form the boundary between the radioactive primary (Class 1 piping) and the nonradioactive secondary systems. There are two identical SGs installed in containment, one in each RCS loop. The SG is a vertical shell and tube heat exchanger where heat transferred from a single-phase fluid at high temperature and pressure (RCS) on the tube side is used to generate a two-phase (steam-water) mixture at a lower temperature and pressure on the shell side. The reactor coolant flows through the primary side, or inverted U-tubes, entering and leaving through the nozzles located in the hemispherical bottom head of the SG. The primary head is divided into inlet and outlet chambers by a vertical partition plate extending from the head to the tube sheet.

The steam-water mixture is generated on the secondary or shell side. Feedwater entering the SGs through a feed ring mixes with recirculated fluid and flows downward around the tube bundle inner shroud, then enters the tube bundle area where heat is transferred from the RCS. A small portion of the tube bundle located near the tubesheet functions as a preheater to raise the temperature of the fluid to the saturation point. The remaining area of the tube bundle secondary side operates in the heat transfer nucleate boiling region. The wet vapor rises and is dried to a near moisture-free condition as it exits the SG at the outlet nozzle at the top of the shell.

At steady-state conditions, the fluid inventory and heat content on both the primary and secondary sides of the steam generator is constant, requiring a virtually constant mass flow on the primary side and a makeup (feedwater) mass flow rate that matches the combined steam flow and blowdown mass flow rates.

Additional details about the steam generators are provided in Section 5.4.2 of the Ginna UFSAR.

The subcomponents of the steam generators that require AMR are indicated in Table 2.3.1-5 of the LRA along with each subcomponent's passive functions and references to the corresponding AMR tables in Section 3 of the LRA. The component groups identified in the table include primary inlet and outlet nozzles and safe ends, tubesheet, divider plate, U-tubes, primary manways, SG shell and transition cone, feedwater nozzle, steam outlet nozzle, steam flow restrictor, blowdown piping nozzles and secondary side shell penetrations, secondary closures, internal shroud, primary and secondary decks, lattice grid tube supports, U-bend restraints, primary channel head, primary manway bolts, secondary side closure bolts, support pads, and seismic lugs. The intended functions identified are pressure boundary, flow distribution, heat transfer, flow restriction, structural support, and mechanical closure integrity.

2.3.1.5.2 Staff Evaluation

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

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

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

The staff did not identify any omissions.

2.3.1.5.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's response to the staff's RAI to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified those portions of the SGs and their associated (supporting) SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified those portions of the SGs and their associated (supporting) SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.1.6 Reactor Coolant (Non-Class 1)

2.3.1.6.1 Summary of Technical Information in the Application

Reactor coolant system Class 1 components, steam generators, the pressurizer, and reactor vessel are reviewed and evaluated as unique specific topical areas. For clarity, the system drawings for non-Class 1 RCS components include the above-listed RCS equipment, but the Class 1 portion is clearly denoted with flags.

The non-Class 1 RCS components include all of the safety class 2, 3, and non-nuclear safety grade equipment used to functionally support the RCS. Non-Class 1 RCS equipment is used to sense and provide signals for reactor trip and engineered safety features (ESF) actuation. Equipment included within the system boundary is also used for safe shutdown following fires and SBO events. The non-Class 1 RCS components system also contains equipment that is environmentally qualified.

The principal components of the non-Class 1 RCS components system include all RCS interconnected non-Class 1 piping instruments and instrument lines, RCP motor coolers and heat exchangers, and the pressurizer power-operated relief valve (PORV) nitrogen actuation system. Also included within the evaluation boundary are the PORV and safety valve downstream tail piping up to and including the pressurizer relief tank, the reactor vessel level monitoring system, the low RCS loop level instrumentation, in-core nuclear detector drive detector isolation, and the essential piping valves and ancillary equipment necessary to support the function of the RCS.

Additional details of the RCS non-Class 1 components are provided in Sections 5.1, 5.2, and 5.4, and Table 6.2-15a of the Ginna UFSAR.

The component groups for this system that require AMR are indicated in Table 2.3.1-6 of the LRA along with each component group's passive functions and references to the corresponding AMR tables in Section 3 of the LRA. The component groups identified in the table include accumulator, condensing chamber, cooler, containment spray (CS) components, fasteners (bolting), heat exchanger, operator, pipe, seal table, strainer housing, temperature element, and valve body. The intended functions identified are pressure boundary, mechanical joint integrity, heat transfer, and support of in-core instrumentation.

2.3.1.6.2 Staff Evaluation

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

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

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

The staff did not identify any omissions.

2.3.1.6.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's response to the staff's RAI to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified those portions of the reactor coolant (non-Class 1) and its associated (supporting) SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified those portions of the reactor coolant (non-Class 1) and its associated (supporting) SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.1.7 Evaluation Findings

On the basis of this review, the staff concludes that the applicant has adequately identified the reactor system components that are within the scope of license renewal, in accordance with the requirements of 10 CFR 54.4(a), and that the applicant has adequately identified the reactor system components that are subject to an AMR, in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.2 Engineered Safety Features Systems

In Section 2.3.2, “Engineered Safety Features Systems,” of the Ginna LRA, RG&E described the SSCs of the ESF that are subject to AMR for license renewal.

2.3.2.1 Safety Injection

2.3.2.1.1 Summary of Technical Information in the Application

As described in the LRA, the safety injection (SI) system supports RCS inventory and reactivity control during accident and post-accident circumstances by automatically delivering borated water to the reactor vessel for cooling under high and low reactor coolant pressure conditions. Additionally, the system serves to insert negative reactivity into the reactor core in the form of borated water during an uncontrolled plant cooldown following a steam line break or an inadvertent valve operation. The SI system is also credited for use in safe shutdown following some fires and contains components that are part of the Environmental Qualification Program.

Adequate core cooling following a loss-of-coolant accident (LOCA) is provided by the SI system, which operates as follows:

(1) injection of borated water by the passive accumulators

(2) injection by the high-pressure SI pumps drawing borated water from the refueling water storage tank

(3) injection by the RHR pumps also drawing borated water from the refueling water storage tank

(4) recirculation of reactor coolant and injection water from the containment sump to the RCS by the RHR pumps and the SI pumps, if needed (piggy-back operation)

The principal components of the SI system are two passive accumulators (one for each loop), high-head SI pumps, interface with low-head SI pumps (RHR pumps), and the essential piping and valves. The accumulators are passive devices that discharge into the cold leg of each loop. During modes 1 and 2, the refueling water storage tank (RWST) is aligned to the suction of the high-head SI pumps and RHR pumps. The containment spray system shares the RWST liquid capacity with the SI system. After the injection phase, coolant spilled from the break and water injected by the SI system and the containment spray is cooled and recirculated from the sump to the RCS by the low-pressure SI system or, if needed, by the high-pressure SI system.

Several fluid systems interface with the SI system. They include reactor coolant, waste disposal, RHR, plant air, CS, spent fuel cooling and fuel storage, chemical and volume control, CCW, and service water.

Additional SI system details are provided in Section 6.3 and Table 6.2-15a of the UFSAR.

The component groups for this system that require AMR are indicated in Table 2.3.2-1 of the LRA along with each component group's passive functions and references to the corresponding AMR Tables in Section 3 of the LRA. The component groups identified in the table include accumulator CS components, fasteners (bolting), flow element, heat exchanger, indicator, orifice, pipe, pump casing, tank, and valve body.

The intended functions identified are pressure boundary, joint integrity, heat transfer, and flow restriction.

2.3.2.1.2 Staff Evaluation

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

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

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

The staff did not identify any omissions.

2.3.2.1.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's response to the staffs RAI to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified those portions of the SI system and its associated (supporting) SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified those portions of the SI system and its associated (supporting) SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.2 Containment Spray

2.3.2.2.1 Summary of Technical Information in the Application

The CS system, in conjunction with the containment ventilation system, is designed to remove sufficient heat from the containment atmosphere following an accident condition to maintain the containment pressure below design limits. The CS system, in conjunction with the sodium hydroxide (NaOH) tank, is also capable of reducing the iodine and particulate fission product inventories in the containment atmosphere such that the offsite radiation exposure resulting from a LOCA is within the guidelines established by 10 CFR Part 100. The CS system also contains components that are part of the Environmental Qualification Program.

The principal components of the CS system include two pumps, one tank, two spray headers, two eductors, spray nozzles, and the essential piping and valves. The system initially takes suction from the RWST. When a low level is reached in the RWST, the spray pump suction is fed from the discharge of the RHR pumps if continued spray is required. During the period that the spray pumps draw from the RWST, approximately 20 gpm of spray additive will be added to the refueling water in each train by using a liquid eductor enabled by the spray pump discharge. The fluid passing from the NaOH tank will then mix with the fluid entering the pump suction. The result will be a solution suitable for the removal of iodine. The CS system provides a 100 percent redundant backup to the containment post-accident charcoal system for iodine removal capability following a LOCA. For operation in the recirculation mode, water is supplied through the RHR pumps.

2.3.2.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.2 and UFSAR Sections 6.2.2 and 6.5.2 to determine whether there is reasonable assurance that the components of the CS system within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of license renewal. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

The review confirmed the applicant's identification of the intended functions of the CS system that meet the scoping criteria of 10 CFR 54.4(a). The review also confirmed that Table 2.3.2-2 of the LRA identifies the CS system components that have intended functions that meet the requirements of 10 CFR 54.4(a) and are subject to an AMR in accordance with 10 CFR 54.21(a)(1). On the basis of this review, the staff concludes that the applicant's scoping and screening of the CS system is in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

2.3.2.2.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's response to the staff's RAI to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified those portions of the CS system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified those portions of the CS system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.3 Residual Heat Removal

2.3.2.3.1 Summary of Technical Information in the Application

The emergency core cooling system (ECCS) includes the use of the RHR system. The system automatically delivers borated water to the reactor vessel for cooling under low reactor coolant pressure conditions. The RHR system, in conjunction with the main and auxiliary steam system, is designed to transfer the fission product decay heat and other residual heat from the reactor core to the CCW system and the atmosphere at a rate such that design limits of the fuel and the primary system coolant boundary are not exceeded. The RHR system also contains components credited for use in safe shutdown following some fires and components that are part of the Environmental Qualification Program.

Adequate core cooling following a LOCA is provided by the SI (emergency core cooling) system, which operates as follows:

(1) injection of borated water by the passive accumulators

(2) injection by the high-pressure SI pumps drawing borated water from the RWST

(3) injection by the RHR pumps also drawing borated water from the RWST

(4) recirculation of reactor coolant and injection water from the containment sump to the RCS by the RHR pumps

The principal components of the RHR system are two RHR (low-head SI) pumps, two heat exchangers, and the essential piping and valves. The RHR system discharge line is not used for an ECCS function that would require motor-operated valve (MOV)-720 or MOV-721 to open; however, a branch of the RHR discharge line provides low-pressure safety injection to the reactor vessel via parallel lines with one normally closed motor-operated valve (MOV-852A or B) and one check valve (CV-853A or B) in each line.

During modes 1 and 2, the RWST is aligned to the suction of the high-head SI and RHR pumps. After the injection phase, coolant spilled from the break, and water injected by the SI system and the containment spray, is cooled and recirculated to the RCS by the low-pressure SI (RHR) system or, if needed, by the high-pressure SI system.

If RCS depressurization to below the shutoff head of the RHR pumps occurs before the injection mode of the SI system is terminated, the RHR pumps will be used in the recirculation mode. The RHR pumps will take suction from the containment sump, circulate the spilled coolant through the RHR heat exchangers, and return the coolant to the reactor via the reactor vessel nozzles. If depressurization of the RCS proceeds slowly, the high-pressure SI pumps are aligned to take suction from the RHR pumps and inject flow into the RCS cold legs. The RHR pumps and heat exchangers, in conjunction with the CS system, may also be used during the recirculation phase to supply water from the containment sump for use in heat and pressure control of the containment atmosphere.

After the steam generators have been used to reduce the reactor coolant temperature to 350 °F, decay heat cooling is initiated by aligning the RHR pumps to take suction from the RCS loop A hot leg and discharge through the RHR heat exchangers to the loop B cold leg.

Several fluid systems interface with RHR. They include reactor coolant, SI, CS, chemical and volume control, and CCW.

Additional RHR system details are provided in Section 6.3.2.3, Section 5.4.5, and Table 6.2-15a of the UFSAR.

The component groups for this system that require AMR are indicated in Table 2.3.2-3 of the LRA along with each component group’s passive functions and references to the corresponding AMR tables in Section 3 of the LRA. The component groups identified in the table include fasteners (bolting), flow element, heat exchanger, indicator, orifice, pipe, pump casing, switch, temperature element, and valve body.

The intended functions identified are pressure boundary, joint integrity, heat transfer, and flow restriction.

2.3.2.3.2 Staff Evaluation

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

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

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

After completing the initial review, the staff requested in RAI 2.3.2.3-1 that the applicant provide additional information on the RHR. Screen assemblies and vortex suppressors are normally used in the containment sump which provides water for the ECCS recirculation phase, and one of the intended functions is to protect the ECCS pumps from debris and cavitation due to harmful vortex following a LOCA (Ginna UFSAR, Section 5.4.5.4.3). The staff asked the applicant to explain why the subject components were not identified as within scope in Table 2.3.2-3 of the LRA, which listed component groups for the RHR system that require an AMR.

By letter dated May 13, 2003, the applicant responded to the staff's RAI. The applicant stated that the sump screens were not included in Table 2.3.2-3 of the LRA because they are considered civil/structural components rather than ECCS components. The screens are within the scope of the Rule and are evaluated within the containment structure. LRA Section 2.4.1 provides a description confirming their inclusion. The screen is manufactured from stainless steel and as such is evaluated within the commodity group asset CV-SS(SS)-INT as described in Table 2.4.1-1. The RHR system design does not employ mechanical vortex suppressors. Section 5.4.5.4.3 of the UFSAR describes the instrumentation used to verify that vortexing has not occurred during reduced RCS inventory operations.

The staff did not identify any omissions.

2.3.2.3.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's response to the staff's RAI to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified those portions of the RHR system and its associated (supporting) SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified those portions of the RHR system and its associated (supporting) SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.4 Containment Hydrogen Detectors and Recombiners

2.3.2.4.1 Summary of Technical Information in the Application

The containment hydrogen detectors and recombiners detect and control combustible gas mixtures in the primary containment atmosphere. Two trains of containment hydrogen detectors and hydrogen recombiner units are available to the plant. Portions of these trains are environmentally qualified. Because containment hydrogen buildup is a relatively slow process, the recombiner equipment located outside of containment is maintained at a lesser degree of prompt readiness than any other engineered safety feature. Those portions of the recombiner system are considered nonsafety-related components whose failure could prevent the satisfactory accomplishment of a safety-related function. The principal components of the detection portion of the containment hydrogen detection and recombiner system include hydrogen concentration monitoring devices, local analyzer/control panels, remote monitoring/control panels, and their corresponding essential piping and valves. The recombiner portion consists of two blowers and combustion chambers complete with main burner, two igniters (one a spare), a pilot burner, a dilution chamber, two control panels, and the corresponding essential piping and valves. Each combustor is fired by an externally supplied fuel gas, employing containment air as the oxidant. The air supply blowers deliver primary combustion air and quench air to reduce the unit exhaust temperature.

The hydrogen monitoring system is capable of operation during post-accident conditions. The monitors are normally maintained in an isolated standby mode. Hydrogen in the containment air is oxidized in passing through the combustion chamber. Hydrogen gas is also used as the externally supplied fuel so that noncondensible combustion products, which would cause a progressive rise in containment pressure, are avoided. Oxygen gas is made up through a separate containment feed to prevent depletion of containment oxygen below the concentration required for stable operation of the combustor.

2.3.2.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.4 and UFSAR Sections 1.5.10 and 6.2.5 to determine whether there is reasonable assurance that the containment hydrogen detector and recombiner components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of license renewal. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

During its review of LRA Section 2.3.2.4 and referenced drawings, the staff determined that additional information was needed to complete its review. By letter dated March 21, 2003, the staff asked the applicant to clarify where in the LRA the “hot box” components are identified as subject to an AMR or to justify their omission (RAI 2.3.2.4-1). Two of these components are shown on license renewal boundary drawing 33013-1278,2-LR, at locations G9 and I9, as subject to an AMR. However, these components are not listed in LRA Table 2.3.2-4.

By letter dated May 16, 2003, the applicant responded that the hot box components are a subcomponent of the containment hydrogen monitor A/B control panel. The hot box is an insulated carbon steel enclosure enveloping the H2 analyzer tubing and moisture separator. The space inside the box is heated to 300 °F in order to prevent condensation within the analyzer tubing. The devices internal to the hot box received a separate AMR and the components are included in the LRA. Because of its unique nature, the hot box was evaluated within the component group of pipe. Although the hot box is not a pressure boundary component, the AMPs applicable are included under component type "pipe," material type "carbon/low-alloy steel," contained in Table 3.3-2, line 40. The staff considers the applicant's response to be acceptable on the basis that these components have been identified as being subject to an AMR and the applicant clarified which component group and AMPs include these components.

By letter dated March 21, 2003, the staff asked the applicant to provide information to support the determination that it is acceptable to terminate the in-scope portion of the hydrogen recombiner system piping at an open valve boundary (RAI 2.3.2.4-2). The hydrogen recombiner system piping network branches with one path going to the hydrogen combustor and the other branch going to out-of-scope piping and components leading to the volume control tank. The branch leading to the volume control tank can be isolated at valve 1877, shown on license renewal boundary drawing 33013-1274-LR at location A9. This valve is shown as normally open; however, it forms the pressure boundary interface with an out-of-scope system.

By letter dated May 16, 2003, the applicant responded that the valve alignment to operate the hydrogen recombiners, and to maintain the hydrogen concentration in containment at a safe level, is included in Ginna Station procedures S-21.1 and S-21.2. It takes several days after a severe accident for hydrogen generation to reach a level that requires recombiners. Thus, sufficient time is available to perform manual valve alignments. Both procedures isolate the volume control tank from the hydrogen manifold by closing valve 1877 and opening valve 1878. The failure of the downstream, out-of-scope piping would not affect the pressure boundary integrity intended function since this piping would be isolated when the hydrogen recombiner is in use. The staff finds the applicant's response to be acceptable on the basis that sufficient time and approved procedures exist to close the system boundary in the event this system is required to perform its intended function.

By letter dated March 21, 2003, the staff asked the applicant to justify the omission of certain components from being subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1) (RAI 2.3.2.4-3). These components include pipe segments, connectors, and flexible hoses downstream of isolation valves 1868 A-D and 1867 A-D, which connect to the mobile hydrogen tanks. They are not shown as subject to an AMR on license renewal boundary drawing 33013-1274-LR, at locations E6, E7, E10, and E11. By letter dated May 16, 2003, the applicant responded that the pipe segments, connectors, and flexible hoses downstream of the isolation valves, which connect to the mobile hydrogen tanks, were not included in the scope of the LRA since these components are isolated prior to the use of the hydrogen recombiners, as discussed in response to RAI 2.3.2.4-2. The staff finds the applicant's response to be acceptable on the basis that these components will be isolated from the system in the event this system is required to perform its intended function.

2.3.2.4.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's responses to the staff's RAIs to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified those portions of the containment hydrogen detectors and recombiners that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified those portions of the containment hydrogen detectors and recombiners that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.5 Containment Isolation Components

2.3.2.5.1 Summary of Technical Information in the Application

The containment isolation components system contains the nonstructural equipment that performs a containment isolation boundary function where the system containing that equipment has no other safety-related system function. Components evaluated in the containment isolation components system are relied upon to achieve safe shutdown following some fires. The system contains components that are part of the Environmental Qualification Program. The principal parts of the containment isolation components system include pipes and valves. A summary of the system lines penetrating containment and the boundaries employed for containment isolation is presented in UFSAR Table 6.2-15a. Each system whose piping penetrates the containment boundary is designed to maintain or establish isolation of the containment from the outside environment under any accident for which isolation is required, assuming a coincident independent single failure or malfunction occurring in any active system component within the isolated bounds. Piping penetrating the containment is designed for pressures at least equal to the containment design pressure. Containment isolation boundaries are provided as necessary in lines penetrating the containment to ensure that no unrestricted release of radioactivity can occur.

2.3.2.5.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.5 and UFSAR Section 6.2.4 to determine whether there is reasonable assurance that the containment isolation components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1). In the performance of the review, the staff selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of license renewal. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

During its review of LRA Section 2.3.2.5 and referenced drawings, the staff determined that additional information was needed to complete its review. By letter dated March 21, 2003, the staff asked the applicant to confirm that the mechanical portions of all containment penetrations are within the scope of license renewal and subject to an AMR (RAI 2.3.2.5-1).

By letter dated May 16, 2003, the applicant responded that all containment penetrations are included within the scope of license renewal and are designated a system function code K, “provide primary containment boundary,” in UFSAR Section 3.1.1.2.5. The staff finds the applicant’s response to be acceptable as it clarifies that all containment penetrations are within scope.

By letter dated March 21, 2003, the staff asked the applicant to justify locating out-of-scope pipe segments in close proximity to containment penetrations instead of at some minimum distance (RAI 2.3.2.5-2). Unlike plants built after the introduction of the General Design Criteria, Appendix A to 10 CFR Part 50, some of the piping passing through containment penetrations at Ginna has both isolation valves outside the containment and does not have inboard isolation valves. This situation was discussed as part of Topic VI-4, “Containment Isolation System,” in the Ginna Safety Evaluation Program (SEP) Report NUREG-0821.

In such situations, piping and pipe restraints in close proximity to the containment structure adjacent to penetrations will not be subject to an AMR. In the event of a pipe break, dynamic effects, such as pipe whip and jet impingement from rupture of the out-of-scope piping segments, could damage the containment structure or adjacent, in-scope piping and penetrations. This case is similar to non safety-related piping systems that are not connected to safety-related piping but have a spatial relationship such that their failure could adversely impact the performance of piping and components with an intended safety function (Criteria A2 of 10 CFR 54.4). However, in this case, the concern is that the nonsafety-related piping has the potential to cause damage to the containment pressure boundary.

By letter dated May 13, 2003, the applicant responded that all piping penetrations are solidly anchored to the containment wall. As discussed in UFSAR Section 3.1.1.2.5, external guides, stops, increased pipe thickness, or other means are provided, where required, to limit motion and moments. These design features prevent ruptures by making the penetration the strongest part of the system. In addition, all penetrations and anchorages are designed for forces and moments that might result from postulated pipe ruptures. The penetration design itself, as well as the containment isolation boundary on the other side of the 2 ½-ft thick reinforced concrete containment wall, has been designed to withstand these forces. After reviewing the information provided by the applicant in its response, the staff finds the response to be acceptable on the basis that pipe rupture dynamic effects such as jet impingement and pipe whip were considered in the design of the containment penetrations.

2.3.2.5.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's responses to the staff's RAIs to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified those portions of the containment isolation system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified those portions of the containment isolation system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.6 Evaluation Findings

On the basis of this review, the staff concludes that the applicant has adequately identified the ESF systems and components that are within the scope of license renewal, in accordance with the requirements of 10 CFR 54.4(a), and that the applicant has adequately identified the components of the ESF systems that are subject to an AMR, in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.3 Auxiliary Systems

In Section 2.3.3, "Auxiliary Systems," of the Ginna LRA, RG&E (the applicant) described the SSCs of the auxiliary systems that are subject to AMR for license renewal.

2.3.3.1 Chemical and Volume Control

2.3.3.1.1 Summary of Technical Information in the Application

As described in the LRA, the CVCS controls and maintains RCS inventory and purity through the process of makeup and letdown and provides seal injection flow to the RCP seals. In addition to the reactivity control achieved by the control rods, reactivity control is provided by the CVCS, which regulates the concentration of boric acid solution neutron absorber in the RCS. In order to perform these functions, a continuous feed-and-bleed is maintained between the RCS and the CVCS. The CVCS is also credited for use in safe shutdown following SBO events and some fire-related events. Selected large-volume CVCS tanks are considered nonsafety equipment whose failure could affect a safety function due to their potential to cause flooding effects.

The principal components of the CVCS are variable speed charging pumps, tanks, heat exchangers, demineralizers, and the essential piping and valves. The letdown portion of the system consists of a regenerative heat exchanger and a nonregenerative heat exchanger to cool the reactor coolant letdown and three parallel orifice valves to reduce the pressure. The coolant is passed through purification and deborating demineralizers, as necessary, where corrosion and fission products are removed. The coolant is then routed to the volume control tank. Seal return flow passes from the reactor coolant pump seals, through a containment isolation valve and the seal-water heat exchanger, before returning to the volume control tank. The seal return line is at low pressure and temperature. The charging pumps draw from the volume control tank and inject into the RCS, both through the normal makeup path and via the RCP seals.

Several fluid systems interface with the CVCS. They include reactor coolant, waste disposal, RHR, instrument air, spent fuel cooling and fuel storage, service water, CCW, and treated water.

Additional CVCS details are provided in Section 9.3.4 and Table 6.2-15a of the UFSAR.

The component groups for this system that require AMR are indicated in Table 2.3.3-1 of the LRA, along with each component group's passive functions and references to the corresponding AMR tables in Section 3 of the LRA. The component groups identified in the table include condenser, cooler, CS components, fasteners (bolting), filter housing, flow element, heat exchanger, pipe, pulsation damper, pump casing, tank, temperature element, transmitter, and valve body.

The intended functions identified are pressure boundary and joint integrity.

2.3.3.1.2 Staff Evaluation

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

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

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

The staff did not identify any omissions.

2.3.3.1.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's response to the staff's RAI to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified those portions of the CVCS system and its associated (supporting) SCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified those portions of the CVCS system and its associated (supporting) SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.2 Component Cooling Water

2.3.3.2.1 Summary of Technical Information in the Application

The function of the CCW system is to remove heat from safety-related heat exchangers during plant operation, plant cooldown, and post-accident conditions. Components within the CCW system are also credited for use in safe shutdown following some fire events. The principal components of the CCW system are pumps, heat exchangers, the surge tank, and essential piping and valves. A single CCW pump circulates chromated water through parallel flow paths into various components where it picks up heat from other systems and transfers the heat to the service water system via the CCW heat exchangers. The surge tank accommodates expansion, contraction, and in-leakage of water and ensures a continuous CCW supply until a leaking cooling line can be isolated. The component cooling loop serves as an intermediate system between the radioactive fluid systems and the service water system. Since the CCW system loop is used as an ESF, containment isolation valves are not automatically closed. That portion of the loop located outside the containment is not required to be a closed system.

2.3.3.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.2 and UFSAR Section 9.2.2 to determine whether there is reasonable assurance that the CCW system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of license renewal. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

License renewal boundary drawing 33013-1245-LR, at locations E8 and F8, shows that a portion of the CCW system that is subject to an AMR ends at valves 747A and 747B, which are normally shown as open. There are also numerous other portions of the CCW system that are subject to an AMR that end at valves that are normally open to 3/4 inch or less diameter tubing. Section 2.3.3.2 of the LRA does not discuss why the approach of using normally open valves as license renewal boundaries is acceptable. In a letter dated March 21, 2003, the staff requested that the applicant provide additional information to support the basis for the determination that failure of the downstream piping will not affect the pressure boundary intended function (RAI 2.3.3.2-1).

By letter dated May 23, 2003, the applicant responded that the basis for the acceptability of the AMR boundary stopping at an open valve is described in LRA Section 2.1.7.1. The applicant further clarified that each location selected was evaluated to ensure that leakage could be detected and isolation performed prior to the loss of the affected equipment intended function. The affected equipment consideration included reviewing the equipment serviced by the fluid system and equipment subject to the effects of the leak in the out-of-scope piping/tubing (i.e., flooding and equipment damage from the effects of spray). The fundamental principle was that a valve position change establishes the pressure boundary at the boundary valve before a failure in the downstream components can cause a loss of intended function.

The applicant further clarified that valves 747A and 747B were selected as boundary valves because the downstream nonsafety-related piping is not located in an area containing in-scope equipment that could be affected by spray or flooding. The area is routinely toured, and the isolation valves are readily accessible. The flow through the system has an established value of 15 gpm, making even an improbable catastrophic failure detectable and isolable before the loss of volume in the CCW surge tank complicates operations. Furthermore, the leak detection procedure requires operators to confirm that the desired flows are established to CCW loop components (including those served by 747A and 747B), thus necessitating that the operators physically travel to the areas that contain the out-of-scope equipment. All other applications of open boundary valves in the CCW system (typically at instrument branch lines) were subject to the same rigorous review as described above. In all cases, the determination was made that the usage was consistent with the requirements of NEI 95-10 which require that the evaluation boundary includes those portions of the system or structure that are necessary for ensuring that the intended function of the system or structure will be performed.

The staff reviewed the information provided by the applicant. The staff found that the applicant has not adequately described the basis for concluding that a failure in the out-of-scope piping will not result in failure of the CCW system in performing its intended functions. The staff cannot make its finding regarding the acceptability of the applicant's basis without information such as the available methods of detecting piping failure, the inventory of CCW that could be lost through failed piping from the time of detection to failure of the CCW system, the rate of loss of inventory through a failed pipe considering that the system is pressurized, and the time necessary for reasonable assurance that operators could identify and isolate the failed piping. This was Open Item 2.3.3.2-1.

By letter dated December 9, 2003, the applicant stated that the section of the CCW system serving the post-accident sampling system coolers, between valves 747A/K and 747B/J, as well as the piping, tubing, and valve bodies associated with FIC 649, 650, and 651, would be added into the scope of license renewal. The rest of the CCW system not within the scope of license renewal consists of 3/4 inch or smaller tubing and associated valve bodies. If leakage were to occur from these small diameter lines, it would be on the order of a few gallons per minute.

Conservatively assuming a flow rate of 10 gpm, the CCW surge tank could accommodate about 90 minutes of unmitigated leakage without a loss of system function. This would be more than enough time for the operators to recognize lower tank level (low level alarm at 900 gallons), and initiate makeup flow from the reactor makeup water tank. The CCW makeup water pumps, with a capacity of 60 gpm, can provide adequate makeup flow from this tank, which has a capacity of 75,000 gallons, until operators could isolate the leaking section of CCW piping. All of the necessary isolation valves are in locations accessible to perform post-accident operations. Therefore, the staff concludes that the applicant has adequately justified the portion of the CCW system excluded from the scope of license renewal consistent with the requirements of 10 CFR 54.4(a).

The applicant stated that all of the components being added to the scope of license renewal in the CCW system are included within the component groups listed in Table 2.3.3-2 of the LRA. Therefore, the applicant has appropriately identified those portions of the CCW system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1). This resolves Open Item 2.3.3.2-1.

The staff also questioned whether the capability to supply makeup water from the reactor water makeup tank to the CCW system surge tank is necessary for the CCW system to perform its intended functions. In a letter dated March 21, 2003, the staff requested that the applicant provide information to justify exclusion from the scope of license renewal of the SSCs necessary to supply makeup water from the reactor water makeup tank to the CCW system surge tank (RAI 2.3.3.2-2). The staff identified that Section 9.2.2.4 of the Ginna UFSAR describes the CCW system makeup capability as adequate to accommodate normal system leakage during normal and post-accident operation. This section of the UFSAR also states that the CCW lines supplying cooling to the RCPs are not protected from dynamic effects associated with accidents and that, if a cooling line is severed, the water stored in the surge tank after a low-level alarm, together with makeup flow, provides the operator with time to close the valves external to the containment in order to isolate the leak. The UFSAR also states that the CCW system functions of cooling the RHR heat exchanger and the ECCS pumps are essential. The CCW system license renewal flow diagram, 33013-1245-LR, indicates that only the safety-related section of piping from valves 823 and 729 (drawing location D2) to the component cooling surge tank header is within the scope of license renewal. However, the staff concluded that the SSCs necessary to supply makeup water from the reactor water makeup tank to the CCW system surge tank are within the scope of license renewal pursuant to 10 CFR 54.4. That is, the nonsafety-related piping, valve bodies, and pump casings that are necessary to provide a pressure-retaining boundary so that sufficient flow at adequate pressure is delivered from the reactor makeup water tank to the component cooling surge tank are included within the scope of license renewal and subject to an AMR.

By letter dated June 10, 2003, in response to RAI 2.3.3.2-2, the applicant stated that the piping, valve bodies, bonnets, and pump casings that can be used to fill the component cooling surge tank from the reactor water makeup tank, shown on drawing 33013-1245, are not within the scope of license renewal. The applicant cited UFSAR Section 9.2.2.4.1.3, which describes the evaluation performed in SEP Topic IX-3, “Station Service and Cooling Water Systems,” final SER, dated November 4, 1981. The cited evaluation does not include providing makeup water to the CCW system until after a postulated leak is identified and isolated, and repairs are made to restore the flow path to essential equipment. The applicant also references UFSAR Section 9.2.2.2, which identifies the function of the CCW surge tank as ensuring “a continuous component cooling water (CCW) supply until a leaking cooling line can be isolated.” The applicant further explained that through proper aging management of the in-scope CCW system components, system leakage will be minimized and the CCW surge tank will act as the makeup source for “normal” leakage. Therefore, the applicant concluded that a failure of any makeup capability other than that provided by the surge tank will not affect a safety function, so the makeup capability from the reactor makeup water system is out of the scope of the Rule.

The staff cannot reconcile the applicant’s response with the fact that the Ginna CLB relies on makeup to the CCW system in the event of leakage during post-accident operation. The components of the makeup water supply to the CCW system may be required to replace system leakage necessary to maintain operation of the CCW, and as such, are within the scope of license renewal and subject to an AMR per the requirements of 10 CFR 54.4(a)(2). In a letter dated September 16, 2003, the applicant stated that the components from the reactor makeup water tank will be added to the scope of license renewal and subject to an AMR. This was Confirmatory Item 2.3.3.2-1.

By letter dated December 9, 2003, the applicant stated that the piping, valve bodies, and pump casings between the reactor makeup water tank TCH15 and valve MOV 823 in the CCW system were added to the scope of license renewal and are subject to AMR. The branch line boundary valves defining this path include the first normally closed valve, or valve closed by procedure, to perform that evolution. By letter dated December 19, 2003, the applicant provided supplemental information specifying that the boundary valves are the normally open valve 1262 and the following normally closed valves—1217, 1218, 1247A, 1247C, 1239, 1245, 1252, 1256A, 1277B, 1277C, and 4885. The staff reviewed the described boundaries and concluded that the applicant had identified appropriate boundaries to define the components brought within the scope of license renewal, consistent with the requirements of 10 CFR 54.4(a).

With the exception of the reactor makeup water pump casings, all of these components are already included within the component groups in Table 2.3.3-1 of the LRA. For the reactor makeup water pump casings, which are cast iron containing treated water, the applicant stated that a new line item (265a) would be added to Table 2.3.3-1 of the LRA. The applicant changed Table 3.4-2 of the LRA to include the results of the AMR for the pump casing. Therefore, the applicant has appropriately identified those components that form the pressure boundary for makeup to the CCW system that are subject to an AMR, as required by 10 CFR 54.21(a)(1). This resolves Confirmatory Item 2.3.3.2-1.

2.3.3.2.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's responses to the staffs RAIs to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. On the basis of this review, the staff concludes that the applicant has appropriately identified those portions of the CCW system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified those portions of the CCW system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.3 Spent Fuel Pool Cooling and Fuel Storage

2.3.3.3.1 Summary of Technical Information in the Application

The spent fuel pool (SFP) cooling system is designed to remove heat generated by stored spent fuel from the SFP. The heat from the SFP is rejected to the service water system. The SFP is a Seismic Category I design, reinforced concrete structure totally clad with stainless steel. The SFP provides structural support to the spent fuel racks. The spacing and materials of construction of the spent fuel racks work in conjunction with the SFP water chemistry to provide reactivity control. The concrete elements of the SFP are evaluated within the auxiliary building structure. The principal components of the spent fuel cooling and fuel storage system include pumps, tanks, heat exchangers, and essential piping and valves. Hoses are used to connect the skid-mounted equipment to the system. The new and spent fuel storage racks and the pool and transfer canal liner are also included within the spent fuel cooling and fuel storage system.

The spent fuel cooling system was originally designed as a single train, nonsafety-related system. The system has been modified to add additional cooling flowpaths and equipment. The SFP cooling system now consists of three cooling loops. The primary cooling path is loop "B." This loop is safety-related and seismically qualified and functions as the preferred loop for ensuring adequate cooling in the SFP. The backup loops include permanently installed loop "A" and a skid-mounted loop. Together these loops act as a 100 percent backup to the "B" loop in that they are capable of removing the decay heat from stored spent fuel and a full core offload. The SFP cooling piping is arranged so that failure of any line does not drain the SFP. To protect against the possibility of complete loss of water in the SFP, the upper suction line penetrates the SFP near the top of the pool. The lower suction line penetrates the SFP approximately 5 feet 4 inches above the top of the fuel racks to preclude the possibility of draining the pool and to ensure a minimum water level of 5 feet 4 inches above the top of the fuel. The SFP cooling water return line, which terminates at the bottom of the SFP, contains a 1/4-inch vent hole near the normal SFP water level so that the pool water cannot be siphoned. The clarity and purity of the SFP are maintained by passing approximately 60 gpm of the loop flow through a filter and demineralizer. The design temperature of the pool is 180°C (356°F). A cooling system function is required to maintain pool structure within analyzed bounds.

The original spent fuel storage racks provided capacity for the storage of 210 fuel assemblies. In 1976, the NRC approved the replacement of the original racks with a higher density flux-trap type. This expanded the storage capability from 210 to 595 fuel assemblies. In 1984, the NRC approved the conversion of six flux-trap type racks to high-density, fixed-poison type racks. This further expanded the storage capacity from 595 to 1016 fuel assemblies. At this point, the SFP was divided into two regions. Region 1 consisted of three flux-trap type racks to accommodate a full core offload. Region 2 consisted of six high-density, fixed-poison (Boraflex) type racks for the storage of 840 fuel assemblies that satisfied minimum burnup criteria and had cooled for a minimum of 60 days.

In 1998, the NRC approved an additional reracking of the SFP. The six existing high-density Region 2 racks with a combined capacity of 828 storage locations (12 locations out of the previous 840 were lost due to the attachment of new racks) will be retained, and new borated stainless steel racks will be installed. Phase 2 of the rerack effort has not yet been performed. This reconfiguration will result in 541 additional storage locations, for a total of 1369 locations after completion of both phases.

2.3.3.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.3 and UFSAR Section 9.1 to determine whether there is reasonable assurance that the spent fuel cooling and fuel storage system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of license renewal. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

During its review of LRA Section 2.3.3.3 and referenced drawings, the staff determined that additional information was needed to complete its review. By letter dated March 21, 2003, the staff asked the applicant to clarify why the components of the SFP heat exchanger “A” process monitor skid, and the associated piping and valves leading to radiation element RE-20A shown on LR boundary drawing 33013-1250, 2-LR, at location J6, are not within the scope of license renewal and subject to an AMR, while the heat exchanger “B” process monitor skid, having radiation element RE-20B, is shown as subject to an AMR (RAI 2.3.3.3-1).

By letter dated May 13, 2003, the applicant responded that the piping and components leading to RE-20A are only 3/4 inch, and can also be isolated with valves 12520A and 12520B. RE-20B was included because it was a much larger size line (2 ½ inches), and its intended function is pressure boundary only. There is not an electrical function for RE-20A/B. The applicant’s response is consistent with footnote 1 in LRA Table 2.3.3-5, which explains that selected instruments were conservatively included within the scope of license renewal if they are unisolable from a pressure source and are of sufficient size that a system function would be degraded should their pressure boundary fail. The staff reviewed the applicant’s response to

RAI 2.3.3.3-1 and found it to be acceptable on the basis that an unisolable leak in this piping or these components would not degrade the performance of a license renewal intended function.

By letter dated March 21, 2003, the staff requested that the applicant justify the exclusion of the SFP makeup water supply piping and valves from being within the scope of license renewal and subject to an AMR (RAI 2.3.3.3-2). Ginna UFSAR Section 9.1.2.1.1 states that the CLB criteria for the spent fuel storage system are defined, in part, by Regulatory Guide (RG) 1.13. Section C.8 of RG 1.13 states the following:

> A seismic Category 1 makeup system should be provided to add coolant to the pool. Appropriate redundancy or a backup system for filling the pool from a reliable source, such as a lake, river, or onsite seismic Category 1 water-storage facility, should be provided.

Ginna UFSAR Section 9.1.2.2.1 states that water is supplied to the SFP from the RWST by the refueling water purification pump. Alternative sources of makeup water are available from the primary water treatment plant and the reactor makeup water tank or the monitor tanks. However, the refueling water purification pump and associated valves and piping in the flow path from the SFP to the RWST are shown as not subject to an AMR on license renewal boundary drawing 33013-1248-LR, at location F5. The flowpaths from the alternate makeup sources (the primary water treatment plant (location H1), the reactor makeup water tank (location H10), and the monitor tanks) are also not shown as subject to an AMR. From the UFSAR description, the staff believes that the SFP makeup water supply paths should be within the scope of license renewal and subject to an AMR.

By letter dated May 13, 2003, the applicant responded that Ginna was built before RG 1.13 was issued. The applicant further stated that RG 1.13 is used as guidance, but not as a requirement. The applicant's calculations show that it would take well over 5 hours to initiate boiling in the SFP following a complete loss of SFP cooling. With 26 feet of water over the top of the fuel assemblies, and a maximum boil-off rate of 47 gpm, water would not have to be added to the pool for over 3000 minutes (well over 2 days). Based on this calculation, the applicant concluded that there is more than enough time to take corrective operator actions, using a wide variety of equipment not limited to Seismic Category I equipment, should SFP makeup be required.

The staff cannot reconcile the applicant's argument with the fact that these makeup water supply paths are relied upon in Ginna's CLB, not only to offset boiloff due to the loss of SFP cooling, but also to mitigate potential leaks in the SFP liner. The 1998 staff approval of the re-racking of the Ginna SFP was based, in part, on redundancy in the SFP makeup water supply. The applicant specifically cited the RWST and CVCS holdup tanks as sources of SFP makeup in an RAI response dated November 11, 1997. Although these makeup water paths are nonsafety-related, they are within the scope of 10 CFR Part 54 because their failure could prevent satisfactory performance of functions necessary to prevent or mitigate significant offsite exposures resulting from SFP accidents. This was Open Item 2.3.3.3-1.

By letters dated December 9, 2003, and December 19, 2003, the applicant agreed to add the SFP makeup path from the RWST to the SFP into the scope of license renewal in response to Open Item 2.3.3.3-1. The staff reviewed the applicant's response and found it to be acceptable on the basis that inclusion of the SFP makeup path from the RWST into the scope of license renewal provides a makeup water flowpath to the SFP that is adequate for the purpose of license renewal for mitigation of a leak in the SFP liner consistent with Ginna's CLB and RG 1.13. This resolves Open Item 2.3.3.3-1.

By letter dated March 21, 2003, the staff asked the applicant to clarify the status of the stainless steel SFP liner and transfer canal, which the staff was unable to locate as an entry in LRA Table 2.3.3-3 (RAI 2.3.3.3-3).

By letter dated May 13, 2003, the applicant responded that the SFP liner and transfer canal are within scope and subject to an AMR. The component group of "tank" in Table 2.3.3.3-3 describes the stainless steel SFP liner and transfer canal. The staff reviewed the information provided in response to RAI 2.3.3.3-3 and finds the response acceptable because it clarified that the SFP liner and transfer canal components are within the scope of the Rule and subject to an AMR.

By letter dated March 21, 2003, the staff transmitted RAI 2.3.3.3-4, which asked the applicant to justify not identifying reactivity control as an intended function of the borated stainless steel spent fuel racks, in accordance with the requirements of 10 CFR 54.21(a)(1).

By letter dated May 23, 2003, the applicant responded that the reactivity control functions of the spent fuel racks are indicated in the LRA system description and the associated UFSAR references. The applicant agreed that reactivity control is not explicitly stated as an intended function associated with the structural elements representing the racks. NUREG-1800, Table 2.1-4, identifies "provide radiation shielding" as an intended function but does not identify reactivity control. For the purposes of license renewal, reactivity control is an intended function that was considered. The identification of the reactivity control function is indicated by the relationship made in the LRA between the structural elements describing the racks and Table 3.4-1, line 9, which addresses the neutron-absorbing capability. The staff determined that the applicant's response was acceptable because it clarified that reactivity control is an intended function of the borated stainless steel spent fuel racks.

2.3.3.3.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's responses to the staff's RAIs to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. On the basis of this review, the staff concludes that the applicant has appropriately identified those portions of the spent fuel cooling and storage system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified those portions of the spent fuel cooling and storage system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.4 Waste Disposal

2.3.3.4.1 Summary of Technical Information in the Application

The waste disposal system provides equipment necessary to collect, process, and prepare for disposal of potentially radioactive liquid, gaseous, and solid wastes produced as a result of reactor operation. Radioactive fluids entering the waste disposal system are collected in sumps and tanks until subsequent treatment methods can be determined. The consequences of a radioactive release from a subsystem or component are evaluated in UFSAR Section 15.7, which concludes that accidental gaseous and liquid radioactive releases from the waste disposal system will not pose a safety hazard to the public relative to 10 CFR Part 100 releases. The waste disposal system contains two environmentally qualified sump pumps, which discharge to the waste holdup tank. The waste holdup tank provides a holdup capacity reserved to abate RHR pump seal failure spillage. Other system tanks contain volumes of liquid, which if spilled, could prevent the satisfactory accomplishment of a safety-related function. Additionally, components within the system act in concert with structural features to prevent internal floods from propagating.

The principal components of the waste disposal system are the demineralizing systems, waste gas compressors, tanks, and essential piping, pumps, and valves. Liquid wastes requiring cleanup before release are collected and processed by a vendor-supplied demineralization system. Gaseous waste is reused as tank cover gas or stored for decay and subsequent release.

2.3.3.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.4 and UFSAR Sections 3.4.2, 9.3.3, 11.2, 11.3, and 11.4 to determine whether there is reasonable assurance that the waste disposal system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of license renewal. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

During its review of LRA Section 2.3.3.4 and referenced drawings, the staff determined that additional information was needed to complete its review. By letter dated March 21, 2003, the staff asked the applicant to clarify why vertical ball valve 1020C, from the auxiliary building sump basement piping to the auxiliary building sump, is not shown as subject to an AMR on license renewal boundary drawing 33013-1272, 2-LR, at location J4 (RAI 2.3.3.4-1). This component is relied upon to contain radiological releases in the event of an accident.

By letter dated June 16, 2003, the applicant responded that the vertical ball valve 1020C is subject to an AMR. The valve should have been highlighted on the referenced drawing. Its function, however, is not to contain radiological releases but rather to prevent backflow into the

RHR pump pit from the auxiliary building sump. The staff finds the applicant's response to be acceptable on the basis that it clarified that this vertical ball valve is subject to an AMR with an intended function of backflow prevention.

2.3.3.4.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicants response to the staff's RAI to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified those portions of the waste disposal system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified those portions of the waste disposal system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.5 Service Water

2.3.3.5.1 Summary of Technical Information in the Application

The service water (SW) system takes suction from the ultimate heat sink and supplies the cooling water used to provide heat removal from safety-related heat exchangers. The SW system is also the normal suction supply to the standby auxiliary feedwater system and an alternate supply to the preferred auxiliary feedwater system where it is used to provide emergency heat removal from the RCS using secondary heat removal capability. The SW system is also credited for use in safe shutdown following some fires. The SW system provides multiple water source flowpaths to ensure the availability of the ultimate heat sink. These flowpaths include nonsafety-related equipment whose failure could prevent the satisfactory accomplishment of a safety-related function. Portions of the SW distribution system serving safeguards equipment are designed as Seismic Category I. Other portions of the SW system serving nonsafety loads are designated as nonseismic and are capable of being isolated from the Seismic Category I portion. The principal components of the SW system are four service water pumps, a single loop supply header, essential isolation valves, and other essential piping including the normal and standby discharge header and the intake piping systems that transport water from the lake to the SW pump suction bay. The SW system consists of a single loop header supplied by two separate, 100 percent capacity, safety-related pump trains. The loop header supplies the cooling water to safety-related and nonsafety-related components and system heat exchangers inside the containment, auxiliary, intermediate, turbine, and diesel generator buildings. The nonsafety-related and long-term safety functions (e.g., component cooling water heat exchangers) can be isolated from the loop header through use of redundant motor-operated isolation valves. In addition to supplying cooling water to heat exchangers, the system supplies seal water to the circulating water pumps and the vacuum pumps, flushing water to the traveling screens, and makeup water to the fire water storage tank via the fire booster pump.

2.3.3.5.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.5 and UFSAR Sections 3.3.3.3.7 and 9.2.1 to determine whether there is reasonable assurance that the SW system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of license renewal. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

In a letter dated March 21, 2003, the staff requested that the applicant justify why the corrugated metal pipe, which discharges service water to Deer Creek, was not included in the scope of license renewal and subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1) (RAI 2.3.3.5-1). LRA Section 2.4.2.11 states that the redundant SW discharge line is occasionally placed in service for such activities as surveillance testing or maintenance work. License renewal boundary drawing 33013-1250,2-LR, at location F11, shows a portion of the redundant service water discharge line as a corrugated metal pipe to Deer Creek. This corrugated metal pipe is not shown as being subject to an AMR on that drawing, nor could this pipe be identified in LRA Table 2.3.3-5 under either the pipe or the structure component groups. Obstruction of this flowpath could prevent the SW system from performing its intended function when the primary flowpath is not in service or is unavailable.

RAI 2.3.3.5-1 also noted that an inspection program was recommended for the Deer Creek culvert in the Ginna SEP (see page 4-7 of NUREG-0821) to minimize the potential for flooding of Deer Creek. The applicant was asked to clarify if the corrugated metal SW discharge pipe empties into Deer Creek above or below the culvert identified by the SEP report and to discuss the measures taken to prevent flooding of the alternate SW discharge if Deer Creek is flooded.

By letter dated May 23, 2003, the applicant responded that the safety-related redundant SW discharge shown on drawing 33013-1250,2-LR, flows into an intermediate structure before it makes its way through the corrugated pipe and into Deer Creek. The intermediate structure is a reinforced concrete “pillbox.” The concrete pillbox is configured to account for the possibility that the normal (testing) discharge path provided by the corrugated pipe may become blocked. The discharge structure is designed so that discharge flow can exit the pillbox through above-grade openings. The discharged water then gravity flows across the yard and into Deer Creek. Because the corrugated discharge pipe is only a testing convenience feature, it does not perform a license renewal intended function, is not within the scope of license renewal, and consequently does not require an AMR.

The corrugated pipe empties slightly above the normal Deer Creek culvert (bed). The safety-grade pillbox empties several feet above that level. The inspections of the Deer Creek culvert referenced in the SEP are conducted to ensure that debris flowing down, or falling into the creek, does not create a damming effect during periods of high flow and exacerbate any flooding effects. The redundant discharge flowpath is always available, even during periods of high flow, because the “pillbox” is located above the top of the creek bank.

The staff finds the applicant’s response to RAI 2.3.3.5-1 to be acceptable on the basis that it clarified that the license renewal drawings show that a continuous flowpath exists from the SW system to the discharge to Deer Creek and it has been included within the scope of license renewal.

By letter dated March 21, 2003, the staff requested that the applicant justify why a portion of the SW system piping is not subject to an AMR which connects two parallel portions of the SW system piping that are subject to an AMR at valves 4733, 4651B, and 4562B that are shown as normally open on license renewal boundary drawing 33013-1250,3-LR, at locations I2, I7, and J7 (RAI 2.3.3.5-2). Two issues were raised in this RAI regarding this piping.

First, this piping run has two parallel trains containing air conditioning water chiller units SCI03A and SCI03B which cool the chilled water system. Drawing 33013-1920 for the chilled water system indicates that the chilled water system cools the control room ventilation system. These components are all identified as augmented quality on the drawings. Section 9.4.3 of the Ginna UFSAR states that the function of the control room ventilation system is, in part, to ensure the operability of control room components during normal operating, anticipated operational transient, and design-basis accident conditions. The staff infers that this statement applies to the cooling function of the system because the filtration and boundary integrity functions do not support control room equipment operability. UFSAR Section 6.4 states that the control room ventilation system cools the recirculated air as required using chilled water coils. Neither LRA Section 2.3.3.5, Section 2.3.3.10, nor Section 2.3.3.15 provides an adequate basis for excluding the associated systems and components from an AMR. The applicant was requested to provide information identifying important-to-safety portions of the SW, chilled water, and control room ventilation systems as SCs subject to an AMR, or to justify their exclusion from being subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

By letter dated May 13, 2003, the applicant responded that those portions of the SW, chilled water, and control room ventilation systems that meet the requirements for being subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1) are identified in the LRA. While UFSAR Sections 9.4.3 and 6.4 describe all the design functions of the control room area ventilation system, only some design functions meet the inclusionary criteria in 10 CFR 54.21(a)(1). While control room cooling via chilled water with the heat ultimately rejected to SW is the preferred method, it is not the only method and does not take into account cooling via radiant heat conduction into the surrounding building members nor the cooling provided by the exchange of air through the filtration and pressure boundary equipment. The components addressed in this question were reviewed under item III.D.3.4, “Control Room Habitability,” as part of NUREG-0737 (final docketed SER dated April 11, 1983). That review included the understanding that, under certain accident conditions, SW to the chiller units is automatically isolated, thus rendering this heat removal media ineffective. Plant operating experience supports the assessment that control room equipment remains functional and operable without the use of the chiller packages to condition the air. Thus, the basis for the exclusion of these components from the scope of license renewal is that they are not important to safety and do not perform any functions listed in the scoping criteria requirements of 10 CFR 54.4.

The staff evaluated the applicant's response to RAI 2.3.3.5-2. The staff did not identify information in the references cited by the applicant that provides the information needed to support exclusion of the piping from the scope of license renewal. The staff does not agree with the applicant's assertion that the isolation of the cooling water supply implies that control room cooling function is not required by the Ginna Station CLB, as the cooling function could be restored when required. Therefore, the staff requested that the applicant provide additional references demonstrating that the Ginna Station CLB does not credit control room cooling using the SW system following an accident to assure the continued operability of safety-related equipment needed for accident mitigation. This was Confirmatory Item 2.3.3.5-1.

By letter dated December 9, 2003, and as supplemented by letter dated January 9, 2004, the applicant stated that Ginna Station's design basis does not rely on forced control room cooling to maintain control room habitability in the event of an accident. An evaluation was performed to calculate limiting post-LOCA control room conditions, and it was shown that temperatures required for reliable equipment operation were maintained without forced cooling. Therefore, the applicant has appropriately justified the exclusion of the SW piping from the scope of license renewal. This resolves Confirmatory Item 2.3.3.5-1.

The second issue the staff identified relates to failure of the piping not subject to an AMR, which may affect the pressure boundary intended function of the piping that is subject to an AMR. LRA Section 2.3.3.5 does not discuss why this approach is acceptable. The applicant was asked to provide additional information to support the basis for this determination. For example, the applicant could discuss the steps in the procedures for identifying the locations of breaks, and for closing the valves, the amount of time required to complete these steps, and the consequences if the valves are not closed following a break of the piping that is not subject to an AMR.

In response to the second issue raised in RAI 2.3.3.5-2, the applicant noted that the basis for the acceptability of the AMR boundary stopping at an open valve is described in LRA Section 2.1.7.1. In this case, MOVs 4733 and 4663 may receive an automatic closed signal isolating the downstream nonsafety piping, or they can be remotely closed should the need arise to perform SW leak isolation. Normally open manual valves 4651B and 4562B are also accounted for in the LRA boundary description. Each of the valves under discussion can be closed for leak isolation before it has deleterious effects on nearby safety systems. With regard to valves 4651B and 4562B, the physical configuration and fluid dynamics in the SW discharge header, where those lines connect, make for very low-pressure conditions after the upstream MOVs are closed.

Plant procedure AP-SW.1, "Service Water Leak," provides guidance for detecting and mitigating leaks. The procedure invokes an attached instruction set (ATT-2.1) whose very first step is to isolate the nonsafety portion of the SW system from the safety portion. That step includes ensuring that at least one of the air conditioning SW loop isolation valves (MOVs 4733 and 4663) is closed. Additionally, the consequence of the piping failure in the area containing the system components under discussion, from the event onset to leak isolation, has been evaluated. The evaluation contains a discussion of how much time is available for leak onset until safety-related equipment might be affected, as well as a description of detection methods. UFSAR Section 3.6.2.4.8.1 provides a summary of this evaluation. The staff found this justification for the location of the license renewal scope boundary at a normally open valve acceptable.

The information provided by the applicant regarding acceptability of the AMR boundary stopping at an open valve was evaluated by the staff. The staff found the applicant's response to be acceptable because it established that each of the valves under discussion can be closed for leak isolation before it has deleterious effects on nearby safety systems. During its review of LRA Section 2.3.3.5 and the referenced license renewal drawings, the staff determined that there was an apparent discrepancy in license renewal boundary drawing 33013-1250,1-LR, at location C8, which shows a section of 14-inch piping connecting to line 16-SW-125-1 as not subject to an AMR. This pipe section connects to a piping section that is subject to an AMR. By letter dated March 21, 2003, the staff asked the applicant to clarify if the exclusion of this pipe section from the scope of license renewal was intentional, or the result of a drafting error (RAI 2.3.3.5-3). If the exclusion of this section was intentional, the applicant was asked to justify the exclusion from the scope of license renewal and being subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

By letter dated May 13, 2003, the applicant responded that the section of 14-inch piping connecting to line 16-SW-125-1 shown on drawing 33013-1250,1-LR, at location C8, as not in scope, reflects a typographical error, and the section is in scope. The staff finds this response acceptable because it clarifies that the pipe section in question is within the scope of license renewal and subject to AMR.

In a letter dated March 21, 2003, the staff identified major portions of the SW system discharge lines, shown on drawings 33013-1250,1-LR (downstream of expander at the end of pipe section 6-SW-125-1, at location I2); 33013-1250,3-LR (downstream of valve 4614, at location H2); 33013-1885,1-LR (beginning with pipe 14-SW-125-1, at location E12 and beginning with the pipe section with identifier 125-9, at location J9); and 33013-1885,2-LR, that are shown as not being subject to an AMR. The drawings indicate that the discharge lines include sections of underground piping. Should these sections of piping fail to remove water from the SW system, the intended functions of the SW system will be impaired. The applicant was requested to provide information identifying these sections of piping as components subject to an AMR or to provide the basis for the determination that these piping sections should not be subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1) (RAI 2.3.3.5-4).

For the cases cited above referencing license renewal drawings 33013-1885,1-LR, and 33013-1885,2-LR, the transitions from piping sections requiring an AMR to those not subject to an AMR occur at boundaries between drawings. The staff requested that if the boundaries are not changed, the applicant provide information to precisely locate these boundaries between piping sections subject to an AMR and piping sections not subject to an AMR.

By letter dated May 13, 2003, the applicant responded that the piping shown on drawing 33013-1250,1-LR, downstream of expander at the end of pipe section 6-SW-125-1, at location I2, to the discharge header, including the discharge canal up to the lake, is in the scope of license renewal. This piping is evaluated in SW Table 3.4-1, line 16, and Table 3.4-2, lines 210 and 211.

The piping on drawing 33013-1250,3-LR, downstream of valve 4614 at location H2, is correctly shown as being out of scope. There are several normally closed valves downstream of 4614 which could be used to isolate a break in the piping.

The 14-inch SW branch piping, shown on drawing 33013-1885,1-LR, at location E12, is evaluated in the LRA. The connecting discharge canal up to the lake is also evaluated in the LRA and should be shown on the drawings as requiring an AMR. This piping is evaluated in SW Table 3.4-1, line 16, and Table 3.4-2, lines 210 and 211.

The staff evaluated the applicant's response and determined that the applicant's statement that there are several normally closed valves downstream of 4614, which could be used to isolate a break in the piping, is too imprecise for use in future audits. The staff required that the applicant specify the exact location of the interface between the in-scope and out-of-scope piping segments and specify whether all of the piping and components within the in-scope boundaries are subject to an AMR. By letter dated July 11, 2003, the applicant responded that the exact location where the change occurs from in-scope to out-of-scope is at, and includes, valve 4614. Downstream, the service water piping and components are nonsafety-related and do not meet any of the three criteria for inclusion within the Rule. The upstream piping and components are subject to an AMR as indicated on the SW drawings provided with the application. Only the passive, long-lived components screened were subject to the AMR process. Active components (i.e., flow transmitters, etc.) are not highlighted on the drawings and are not typically subject to AMR. The staff finds the applicant's response acceptable because it clearly identifies the boundary between in-scope and out-of scope piping segments and, together with the information in the LRA, the components that are subject to an AMR.

In a letter dated March 21, 2003, the staff requested that the applicant provide additional information to support the basis for the determination that the traveling screens are not subject to AMR (RAI 2.3.3.5-5). Drawing 33013-1250,1-LR, at locations A1–A4, shows that the traveling screens are not subject to an AMR. The traveling screens perform a coarse filtration function, which protects the SW pumps and other components receiving unfiltered raw water from blockage, and are typically included within the scope of license renewal due to that intended function. The staff asked the applicant to justify the exclusion of these components from the scope of license renewal and being subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

By letter dated June 10, 2003, the applicant responded that neither the intake tunnel nor the traveling screens are credited for the operation of the SW system—only the circulating water system is credited. The "coarse filtration" function of the screens is not credited for the operation of the SW pumps; the pumps themselves are equipped with suction strainers. The applicant further stated that the clearance around the screens and the inlet structure would provide enough flow area to allow operation of the SW pumps, even if the traveling screens were blocked. In addition, another flowpath exists which bypasses the intake tunnel completely. Opening valve 3123B allows flow to be directed from the discharge canal to the SW pumps. This valve and the connecting flowpath are within the scope of license renewal.

The staff evaluated the applicant's response to RAI 2.3.3.5-5 and finds it to be acceptable on the basis that there is an alternate in-scope system for directing flow from the discharge canal to the SW pumps. Therefore, the traveling screens need not be included in the scope of license renewal.

2.3.3.5.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's responses to the staff's RAIs to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. On the basis of this review, the staff concludes that the applicant has appropriately identified those portions of the SW system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified those portions of the SW system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.6 Fire Protection

2.3.3.6.1 Summary of Technical Information in the Application

The applicant described the fire protection (FP) systems in LRA Section 2.3.3.6. The FP systems include fire confinement, and fire detection and suppression. The fire confinement features are discussed in terms of the fire barrier commodity groups described below. The fire detection and alarm system is described as a protective signaling system that alarms locally in selected areas and transmits fire alarm, supervisory, and trouble signals to the control room. The fire suppression systems addressed include fixed water spray and sprinkler systems, fixed Halon systems, hose stations, and portable extinguishers. The water-based suppression systems are supplied from Lake Ontario using redundant fire pumps, one diesel and one electric. The city water supply from the town of Ontario supplements the fire water system by providing water to the yard hydrants and the screenhouse pump area sprinkler system. The fire water system can also be used as backup cooling water for the SFP heat exchangers, auxiliary feed water pumps, and diesel generators.

The fire barrier commodity group includes fire-rated assemblies and fire-rated penetration seals. Fire-rated assemblies are passive FP features used to separate redundant fires safe shutdown capabilities, including fire-rated walls, floors, ceilings, equipment hatches, stairwells, doors, dampers, penetration seals, and fire breaks. Fire-rated penetration seals are openings in a fire barrier for the passage of pipe, cable, etc., which have been sealed so as not to reduce the integrity of the fire barrier. Although commodity groups are used to generically represent the barrier materials, for the purposes of this review, each fire barrier is labeled in the plant with a unique identifier. Plant procedures and drawings specifically detail the construction, repair, and inspection criteria distinctive to the specific application. Plant procedures and drawings also distinguish which barrier is credited in the licensing basis with respect to FP and which barrier is installed for commercial property conservation.

2.3.3.6.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.6, UFSAR Section 9.5.1, and other program documents, such as the Fire Protection Program report, to determine whether there is reasonable assurance that the FP system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review the staff selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of license renewal. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

The fire water supply system includes a 15,000-gallon pressure tank and a 120-gpm fire booster pump to maintain pressure in the fire water system. The system boundary drawing 330B-1990,1-LR, shows the pressure tank in scope but excludes the fire water booster pumps. In a letter dated March 21, 2003, the staff questioned the exclusion of the fire service water booster pump, piping, and valves back to the SW system from the scope of license renewal (RAI 2.3.3.6-1). By letter dated May 13, 2003, the applicant responded that UFSAR Section 9.5.1, along with the associated references, identifies BTP 9.5-1 as the licensing basis for the FP systems for the Ginna plant. The fire water storage tank, jockey pump (fire service water booster pump), and associated appurtenances are not required by the CLB to achieve compliance with the requirements of BTP 9.5-1. Lake Ontario is the source of water for the motor- and diesel-driven fire pumps, not the storage tank. The fire water system can maintain full operability and compliance with the requirements of 10 CFR 50.48 and all other FP commitments without the storage tank and jockey pump in service. Consequently, those components and their associated piping and valve bodies are not subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). However, the applicant elected to perform aging management activities on the fire water storage tank simply because it is a pressurized tank in an occupied space.

The staff evaluated the applicant's position concerning the jockey pump and storage tank and studied the relevant documents (Ginna UFSAR Section 9.5.1 and the associated SER, as well as BTP 9.5-1). The staff transmitted this evaluation to the licensee in The License Renewal Safety Evaluation Report for the R.E. Ginna Nuclear Power Plant, dated October 2003 (ML 032820021). UFSAR Section 9.5.1.2.3.3 states, "A 15,000-gal pressure tank (10,000 gallons of water) and a 120-gpm centrifugal jockey pump maintain system pressure at a minimum of 100 psig." The staff concluded, based upon this review, that the National Fire Protection Association (NFPA) 20, "Standard for the Installation of Centrifugal Fire Pumps," is endorsed by Section 6.b.6 of BTP 9.5-1, which was cited by the Ginna UFSAR as the licensing basis for the plant. The requirement for the jockey pumps/pressure maintenance device is stated in Section 31(e) of the 1972 edition of NFPA 20. The 1978 edition forbids the use of the fire pump for pressure maintenance. The 1996 edition further clarifies this requirement in Section 2-19.5, which states, “The primary or standby fire pump shall not be used as a pressure maintenance pump.” The jockey pump and storage tank and their associated piping and valves perform a pressure maintenance function, as stated in the UFSAR, which protects the large fire pumps from damage during low-flow, high-pressure operation and is an essential part of the fire water system. The staff had disagreed with the applicant regarding not including the fire service water booster pump, piping, and valves in scope of license renewal. This was Open Item 2.3.3.6-1.

By letter dated December 9, 2003, the applicant responded that the passive pressure boundary components of the fire service water booster pump, valves, and associated piping back to the SW system would be included in the scope of license renewal and subject to an AMR. The staff finds the applicant’s response to RAI 2.3.3.6-1 acceptable on the basis that it will include these components within the scope of license renewal and subject them to an AMR. This resolves Open Item 2.3.3.6-1.

Part of the fire water system, from the screenhouse housing the fire pumps to the other plant buildings, is underground. LRA Table 2.3.3-6 references portions of LRA Tables 3.4-1 and 3.4-2 for aging management of the piping component group. The aging management references included in LRA Table 2.3.3-6 under piping do not include references to buried piping, such as LRA Table 3.4.1, item 17. Since item 17 specifically references the Fire Protection Program, it should be included in LRA Table 2.3.3-6. However, none of the references in LRA Tables 3.4-1 or 3.4-2 address internal corrosion of buried (underground) ductile iron piping. LRA Section 2.1.6, “Fire Protection Component Aging Management,” states the applicant will continue to conduct flow tests as part of the fire water system program described in LRA Appendix B, Section B2.1.14. In a letter dated March 21, 2003, the staff asked the applicant to clarify the AMP for underground fire water piping, including the adequacy of flow tests in managing internal corrosion of the underground piping (RAI 2.3.3.6-2).

By letter dated May 23, 2003, the applicant responded that the fire water system program at Ginna Station is implemented by a number of plant procedures, which include activities such as fire pump full-flow capacity tests, velocity flushes of piping and components, operability tests of hydrants and valves, and verification of the capability of the fire water system to maintain pressure during performance tests. The velocity flush procedure includes measurement of flow rate and residual and static pressures, and calculation of the internal pipe roughness at various locations throughout the system. The applicant noted that trending data from periodic velocity flushes has accurately identified degraded internal conditions in sections of buried yard loop piping which were subsequently verified by excavation and internal inspection. In one case, the applicant discovered that a section of unlined ductile iron pipe had been installed during original construction instead of cement-lined pipe as required by piping specifications. In another case, internal obstruction due to biofouling was found at incorrectly installed mechanical clamps. Both conditions were addressed by appropriate corrective maintenance.

In addition to system performance tests, the internal condition of buried system components is evaluated under the Fire Water System Program when they are excavated and disassembled during maintenance activities. Internal remote visual inspections of significant lengths of cement-lined ductile iron pipe have been performed during maintenance activities in 2001 and 2002, and the internal condition of the piping was found to be clean and free of corrosion or obstruction due to fouling/biofouling. On the basis of this response, the staff concurs that the fire service water program adequately identifies the components and aging management programs for the underground fire water piping.

As identified in the LRA, the yard hydrants and portions of the screenhouse building are in the scope of license renewal but are supplied by a nonsafety-related, nonseismic water line from the town of Ontario municipal water system. The screenhouse building is not designed to protect the safety-related components, housed within, against external events or pipe break events. As explained in LRA Section 2.4.2.7, protection against these events is not needed because alternative shutdown means are available, which do not rely upon components housed in the screenhouse. However, the alternate shutdown procedure relies upon the fire hydrants as an alternative source of cooling water for the diesel generators, and as stated above, the yard hydrants are supplied from the nonqualified municipal water system. The staff has reviewed this configuration in the past and found it to be acceptable. As discussed in Topic III-5.B, "Pipe Breaks Outside Containment," of NUREG-0821, the SEP SER issued in December 1982, the NRC concluded that further modification of the screenhouse was unwarranted. It is also likely that degradation of this water supply to the yard hydrants would be quickly noticed, as this supply line is also the source of domestic water to the site. The staff therefore considers the exclusion of the municipal supply line to the yard hydrants from the scope of license renewal to be acceptable, because the Ginna SEP specifically approved this configuration and because it is likely that degradation of this supply would be promptly identified and corrected. This position is similar to the staff guidance on SBO, where the staff has historically relied upon the well-distributed, redundant, and interconnected nature of the grid to provide the necessary level of reliability to support nuclear power plant operations. However, the staff has determined that the plant system portion of the offsite power system that is used to connect the plant to the offsite power source should be included within the scope of the Rule.

The fire barrier commodity groups adequately address the various components as being in scope. However, the AMR references in LRA Table 2.3.3-6 do not specifically address fire-proofing materials mentioned in Section 2.3.3.6. No reference was found in LRA Section 2.4 to the fire-proofing commodity group. In a letter dated March 21, 2003, the staff asked for clarification of whether fire-proofing of structural steel was used as part of in-scope fire barriers and where it was included in the AMR (RAI 2.3.3.6-3).

By letter dated May 13, 2003, the applicant responded that fire proofing of structural steel is used in the Ginna plant at selected locations. For each building that utilizes this feature, the system description in LRA Section 2.4.2 calls out that usage. For example, in LRA Section 2.4.2.3, in the description of features and appurtenances credited in the CLB, item b states, "Selected structural steel building members are coated with a protective material to resist the effects of fires." These materials are evaluated in the FP system as part of fire barriers and are evaluated for aging management in LRA Table 3.4-2, lines 322–329, component type "structure," material "grout." Typically, structural steel coating fire-proofing materials are not considered grouts; however, the applicant's response to this request for clarification has verified that these materials are in scope and are subject to an AMR.

Also listed in the fire barrier commodity groups were fire breaks or stops intended to limit the propagation of fire along a cable tray. Section 9.5.1.1.2 of the UFSAR references the use of fire-retardant coatings for some cable concentrations for cables which did not meet the flame spread qualification of IEEE-383. These coatings are referenced in LRA Table 3.4.2 as fire stop materials. The staff finds the applicant's response to RAI 2.3.3.6-3 acceptable on the basis that it verified that these components are within the scope of license renewal and are subject to an AMR.

The fire detection and alarm system is included in LRA Section 2.1.5.6 as part of the Fire Protection Program necessary to meet the requirements of 10 CFR 50.48 and is identified as being in scope of license renewal in LRA Section 2.3.3.6. Neither LRA Table 2.3.3-6 nor LRA Section 2.5 includes any reference to the AMR of this system or its components. In a letter dated March 21, 2003, the staff requested that the applicant confirm that these systems are in scope and identify where the LRA addresses the AMR of these components (RAI 2.3.3.6-4).

By letter dated May 13, 2003, the applicant responded that the AMR of low-voltage cables and connections is performed in LRA Section 3.7 and is applicable to fire detection and alarm systems. The AMPs are listed in LRA Table 3.7-1. The fire detection and alarm system components are with the scope of license renewal. However, all components are active with the exception of cables, connectors, and other passive electrical devices, which are included in LRA Table 3.7-1. The staff finds the applicant's response to RAI 2.3.3.6-4 acceptable on the basis that it verified that these components are within the scope of license renewal and are subject to an AMR.

Part of compliance with 10 CFR 50.48, Appendix R to Part 50, Section III O, requires an oil collection system be provided for the reactor coolant pumps. LRA Section 2.3.3.6 specifically addresses the components of the oil collection system by referencing LRA Table 3.4.1, line 6, "Components in the Reactor Pump Oil Collection System," including the tank and piping.

2.3.3.6.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's responses to the staff's RAIs to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. On the basis of this review, the staff concludes that the applicant has appropriately identified those portions of the FP system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified those portions of the FP system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.7 Heating Steam

2.3.3.7.1 Summary of Technical Information in the Application

The heating steam system supports habitability and equipment reliability by maintaining plant area temperatures within acceptable bounds. In addition to supporting ventilation functions, the heating system also provides process steam for the waste disposal system evaporator. The system does not perform any nuclear safety function. (Note that at one time the heating steam penetrated containment. Those blanked-off sections of abandoned pipe are evaluated with the containment isolation components system discussed in Section 2.3.2.5.) The heating steam system contains pressurized, high-temperature fluid and has pipe routing and equipment locations in close proximity to safety-related equipment. Accordingly, some localized pipe segment and equipment meet the scoping criteria of 10 CFR 54.4(a)(2) (they are considered nonsafety components whose failure could prevent the satisfactory accomplishment of a safety function).

The heating steam system is categorized as a high energy system. Consequently, the effects of heating steam pipe breaks have been evaluated. Evaluations were subsequently performed to ensure the plant could achieve and maintain safe shutdown following postulated system failures. As a result of the evaluation, pipe whip and jet impingement protection was provided for the 6-inch heating steam line riser located on the intermediate floor of the auxiliary building to protect safety-related electrical equipment in the vicinity of the riser. Additionally, heating steam lines were removed from the relay room and air handling room in order to maintain a mild environment for the purpose of environmental qualification of electrical equipment in the rooms. The mitigative equipment is evaluated in the appropriate civil/structural assessment. As a result of these analyses and modifications, the only portion of the heating steam system considered as nonsafety components whose failure could prevent the accomplishment of a safety function, are those portions of the system contained in the diesel generator rooms.

The principal components of the heating steam system are the boiler, tanks, pumps, condensate collection tanks, unit heaters, and essential piping and valves. The heating steam is provided from the house boiler, located in the screenhouse, or from a connection in the main steam system. The systems provided with house steam include unit heaters in the screenhouse, intermediate building, auxiliary building, turbine building, diesel generator rooms, auxiliary building air handling units, containment purge supply unit, boric acid batch tank, gas stripper, and the boron recycle evaporator.

2.3.3.7.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.7 and UFSAR Sections 3.6 and 9.4.10 to determine whether there is reasonable assurance that the heating steam system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of license renewal. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

During its review of the LRA, the applicant's scoping and screening implementation procedures, and discussions with the applicant, the staff determined that additional information was required with respect to certain aspects of the applicant's evaluation of the 10 CFR 54.4(a)(2) criteria.

For example, the applicant noted that the auxiliary boiler in proximity to the service water pumps in the screenhouse was not included in scope because its failure had been analyzed as part of the SEP and design features had been put in place to mitigate the effects of such a failure. The staff considers that nonsafety-related SSCs, such as the auxiliary boiler, meet the 10 CFR 54.4(a)(2) criteria and, therefore, must be included in the scope of license renewal. By letter dated March 21, 2003, the staff requested that the applicant describe any additional scoping evaluations performed to address the 10 CFR 54.4(a)(2) criteria (RAI 2.1-4, discussed in SER Section 2.1).

In a letter dated May 13, 2003, the applicant responded that it reviewed its 10 CFR 54.4(a)(2) evaluations and concluded that the steam heating system in the screenhouse, including the boiler, met the criteria for 54.4(a)(2) inclusion, and thus it included these components as requiring an AMR. These components will be managed by the Periodic Surveillance and Preventive Maintenance Program described in B2.1.23 of the LRA. In its response dated June 10, 2003, the applicant provided the revised wording for Section 2.3.3.7 and the additional components for Table 2.3.3-7 in the LRA. The staff finds the applicant's response to be acceptable on the basis that these components are considered to meet the 10 CFR 54.4(a)(2) criteria and are subject to an AMR.

During its review of LRA Section 2.3.3.7, the staff determined that additional information regarding several component groups that are subject to an AMR was needed to complete its review. These component groups are identified by the applicant as subject to an AMR; however, the staff could not locate several of the components on the five license renewal boundary drawings. By letter dated March 21, 2003, the staff requested that the applicant provide the drawing numbers and equipment identification numbers for the components in the component groups listed in LRA Table 2.3.3-7 (RAI 2.3.3.7-1).

In a letter dated May 13, 2003, the applicant responded that affected components are shown on license renewal boundary drawing 33013-1914-LR, generally in locations B1–B3 and F1–F3, and should have been highlighted. This is a typographical error. The applicant provided the equipment identification numbers for the affected components as requested. The staff finds the applicant's response to be acceptable on the basis that certain components subject to an AMR were inadvertently not highlighted on the license renewal boundary drawings.

2.3.3.7.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicants response to the staff's RAI to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified those portions of the heating steam system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified those portions of the heating steam system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.8 Emergency Power

2.3.3.8.1 Summary of Technical Information in the Application

The diesel generator emergency power system provides electrical power for safety-related components when the preferred power supply is not available. The emergency power sources become available automatically following the loss of the preferred power supply within a time consistent with the requirements of the ESF and the shutdown systems under both normal and accident conditions. Components within the emergency power system are also credited for use in safe shutdown following some fires. Emergency power system reliability is a critical element in ensuring that the station demonstrates compliance with regulations for SBO. Included in the emergency power system are two safety-related station emergency diesel generators (EDGs) and the technical support center (TSC) diesel generator. Each EDG is capable of automatically starting and sequentially accepting the power requirements of one complete set of safeguards equipment. Each EDG provides the necessary power to cool the core and maintain the containment pressure within the design value for a LOCA (coincident with a loss of offsite power). The diesels start automatically when loss of voltage is sensed on the bus they supply. The EDGs also start automatically upon receipt of a safety injection signal. The EDGs are normally operated from the control room, but EDG A is equipped with a control station that allows the unit to be electrically divorced from the control room and operated locally. The TSC diesel generator can be used to supply a battery charger in order to support vital direct current (DC) for long-term recovery following some fire scenarios.

The principal components of the EDGs include two diesel engines. Each engine is equipped with its own turbo charger, air start subsystem, lube oil and cooling water subsystems, fuel oil subsystem, ventilation system, and essential piping and valves. (Ventilation requirements are evaluated separately within the ventilation systems discussions.) The TSC diesel generator requires its own similar subsystems to function but uses batteries rather than air as a starting mode of force.

2.3.3.8.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.8 and UFSAR Sections 8.3.1.1.6, 9.5.4, 9.5.5, 9.5.6, 9.5.7, and 9.5.8 to determine whether there is reasonable assurance that the emergency power system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of license renewal. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

During review of license renewal boundary drawings 33013-1239-LR, sheets 1 and 2, the staff found that manways associated with the diesel generator fuel oil storage tanks are shown to be subject to an AMR. Also, a similar bolted access cover associated with the diesel generator cooling water expansion tanks is shown to be subject to an AMR on license renewal boundary drawings 33013-1239-LR, sheets 1 and 2. However, the manways and access covers have not been included in Table 2.3.3-8 or Tables 3.4-1 and 3.4-2. Furthermore, Section 9.5.4 of the Ginna UFSAR states that watertight doors have been installed on the concrete manways of the underground diesel oil storage tanks. The purpose of the doors is to prevent the accumulation of water in the manways. Water might seep into the oil through the flanged manhole on the top of each storage tank. Based on the above, the staff believes that the manways and access covers should be subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). By letter dated March 21, 2003, the staff asked the applicant to justify the exclusion of the manways, access covers, watertight doors, and bolting mechanisms from being subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1) (RAI 2.3.3.8-1).

In a letter dated May 13, 2003, the applicant responded that the manways associated with the diesel generator fuel oil storage tank, and the bolted access cover associated with the diesel generator cooling water expansion tanks, are grouped within the component group "tank." Line number 7 in Table 3.4.1 and numbers 335, 337, 340, and 341 in Table 3.4-2 are applicable to these components. The concrete enclosure referred to in UFSAR Section 9.5.4 is evaluated in the LRA within the essential yard structures system in Table 2.4.2-11 under component groups YARD-C-BUR and YARD-CAPTION-EXT. The staff finds the applicant's response to be acceptable on the basis that the identified components are subject to AMR and included in the cited tables of the LRA.

During a review of license renewal boundary drawings 33013-1239,1-LR, and 33013-1239,2-LR, the staff found that foot valves 5919 and 5920 are shown to be subject to an AMR. Note 4 on these drawings indicates that the valves contain a screen. However, Table 2.3.3-8 does not list any screens as a component group subject to an AMR. By letter dated March 21, 2003, the staff asked the applicant to clarify if the screens associated with these valves are subject to an AMR, and if not, to justify the exclusion of these screens from being subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1) (RAI 2.3.3.8-2).

In a letter dated May 13, 2003, the applicant responded that the screens associated with foot valves 5919 and 5920 are subject to an AMR and that the applicable AMPs are listed in Table 3.4-1, line 5—Periodic Surveillance and Preventive Maintenance Program, Fuel Oil Chemistry Control Program, and One-Time Inspection Program. The applicant further noted that currently there is a Reptask P301699 to inspect/clean DG "A" fuel oil storage tank (TDG01A), which includes inspection of valve 5919 and the associated screen, and a Reptask P301700 to inspect "B" tank and valve 5920 and the associated screen. The staff finds the applicant's response to RAI 2.3.3.8-2 to be acceptable on the basis that the screens in question are subject to an AMR and the applicable AMPs are identified.

2.3.3.8.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's responses to the staff's RAIs to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified those portions of the emergency power system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified those portions of the emergency power system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.9 Containment Ventilation

2.3.3.9.1 Summary of Technical Information in the Application

The functions of the containment ventilation system are to provide emergency heat removal from the containment atmosphere, to remove radioactive material from the containment atmosphere, and to provide containment pressure control. Portions of the system maintain containment concrete temperatures below the threshold where long-term aging effects are manifested. Thus, the containment ventilation system is considered to contain non-safety-related equipment whose failure could prevent the satisfactory accomplishment of a safety function (e.g., penetration cooling). The containment ventilation system also contains components used for fire detection and components that are environmentally qualified.

Included within the scope of the containment ventilation system are the following subsystems:

- containment recirculation cooling and filtration system
- control rod drive mechanism cooling system
- reactor compartment cooling system
- refueling water surface and purge system
- containment auxiliary charcoal filter system
- containment post-accident charcoal filter system
- containment shutdown purge system
- containment mini-purge system
- penetration cooling system

The principal components of the containment ventilation system include filters, fans, dampers, valves, heat exchangers, and the essential ductwork and piping. Fire dampers contained in the system are evaluated as a separate commodity group.

The containment recirculation fans, control rod drive mechanism fans, and reactor compartment fans are direct-driven units, each with standby units for redundancy. The fans and motors of these units are provided with vibration detecting devices to detect abnormal operating conditions in the early stages of the disturbance. Each of the associated systems is provided with flow switches to verify existence of air flow in the associated duct system. Dampers in the following systems and ducts are provided with air by dual supply air mains, including primary compartment ducts, dome ducts, containment auxiliary charcoal filter systems, butterfly valves, which isolate the post-accident charcoal filters, and containment purge supply and exhaust ducts. Two of the four fans and coolers plus one containment spray pump (i.e., one train of each system) are required to provide sufficient capacity to maintain the containment pressure within design limits after a LOCA or steam line break accident. The containment recirculation fan cooler electrical connections and other equipment in the containment necessary for operation of the system are capable of operating under the environmental conditions following a LOCA.

The control rod drive cooling system consists of fans and ductwork that draw air through the control rod drive mechanism shroud and eject it to the main containment volume. The reactor compartment cooling system consists of a plenum, cooling coils, fans, and ductwork arranged to supply cool air to the annulus between the reactor vessel and the primary shield and to the nuclear instrumentation external to the reactor. The refueling water surface and purge system supplies air to the surface of the refueling cavity and exhausts from the area above the refueling manipulator crane to protect the operators during refueling operations. The containment auxiliary charcoal filter system's purpose is to absorb radioactive iodine vapor and radioactive particles that may occur as a result of normal primary system leakage inside the containment. The containment shutdown purge system is independent of the main auxiliary building exhaust system and includes provisions for both supply and exhaust air. The supply system includes an outside air connection to roughing filters, heating coils, fans, duct system, and supply penetration with a butterfly valve outside containment and a blind flange inside containment. The exhaust system includes an exhaust penetration with a butterfly valve and a blind flange identical to those above, a duct system, a filter bank with high-efficiency particulate air and charcoal filters, fans, and a building exhaust vent. The shutdown purge supply and exhaust duct blind flanges inside the containment are closed during modes 1, 2, 3, and 4. The containment mini-purge system is capable of purging containment during modes 1 and 2 at a relatively low flow rate (approximately 1500 cfm). The exhaust is through a 6-inch line to the auxiliary building charcoal filters. The penetration cooling system is used to cool hot mechanical containment penetrations. The containment penetration cooling system is designed to prevent the bulk concrete temperature surrounding the penetrations from exceeding 150 °F.

2.3.3.9.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.9 and UFSAR Sections 6.2.2 and 9.4.1 to determine whether there is reasonable assurance that the containment ventilation system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of license renewal. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

During the review of license renewal boundary drawing 33013-1866-LR, the staff identified flanged flexible hoses located at each of the 15 containment penetrations shown for the containment penetration cooling system. The drawing indicated that these hoses were all within the scope of license renewal. However, LRA Table 2.3.3-9 does not list flanged flexible hoses as a component group. By letter dated March 21, 2003, the staff requested that the applicant justify the exclusion of these hoses from the table (RAI 2.3.3.9-1).

By letter dated May 21, 2003, the applicant responded that the 2-inch flanged flexible hoses were included in the component group "pipe" in LRA Table 2.3.3-9. Furthermore, the neoprene lining of these hoses received aging management evaluation as duct in accordance with NUREG-1801, Chapter VII, item F3.1-b.

The staff considers the applicant's response to RAI 2.3.3.9-1 to be acceptable on the basis that clarification was provided indicating that flanged flexible hoses, while not considered a separate component group in LRA Table 2.3.3-9, were incorporated into the table under a different component group heading. Additionally, the lining of these hoses is subject to an AMR, in accordance with NUREG-1801.

2.3.3.9.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's response to the staff's RAI to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified those portions of the containment ventilation system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified those portions of the containment ventilation system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.10 Essential Ventilation

2.3.3.10.1 Summary of Technical Information in the Application

The essential ventilation system functions to maintain temperatures within specified limits in areas containing safety-related equipment. Additionally, the control room emergency air treatment portion of the system is designed to filter the control room atmosphere during periods when the control room is isolated. It is designed to maintain radiation levels in the control room at acceptable levels following design-basis accidents. (Radiation detection and toxic gas monitoring are evaluated within the discussion of the radiation monitoring system.) Ventilation is also required for EDG operation, for the TSC diesel generator and its associated equipment, and the standby auxiliary feedwater pumps, all of which may be used for safe shutdown following some fire events.

Included within the scope of the essential ventilation system are the following subsystems:

- auxiliary building ventilation
- intermediate building ventilation
- standby auxiliary feedwater building ventilation

- diesel generator building ventilation
- control building ventilation
- technical support center ventilation

The principal components of the essential ventilation system include filters, fans, dampers, valves, heat exchangers, conditioning/chiller packages, and the essential ductwork and piping. Fire dampers contained in the system are evaluated as a separate commodity group. The auxiliary building has a nonsafety heating, ventilation, and air conditioning system which provides clean, filtered, and tempered air to the operating floor of the auxiliary building and to the surface of the decontamination pit and spent fuel storage pool. The system exhausts air from the equipment rooms and open areas of the auxiliary building and from the decontamination pit and SFP through a closed exhaust system.

The exhaust system includes a 100 percent capacity bank of high-efficiency particulate air (HEPA) filters and redundant 100 percent capacity fans discharging to the atmosphere via the plant vent. This arrangement ensures the proper direction of air flow for removal of airborne radioactivity from the auxiliary building. Included in the auxiliary building exhaust system is a separate charcoal filter circuit, which exhausts from rooms where fission product activity may accumulate during modes 1 and 2 in concentrations exceeding the average levels expected in the rest of the building. Although no credit for this system is assumed in the plant safety analysis, this circuit is capable of providing exhaust ventilation from the areas containing pumps and related piping and valving, which are used to recirculate containment sump liquid following a LOCA. A full-flow charcoal filter bank is provided in the circuit, along with two 50-percent capacity exhaust fans. The air-operated suction and discharge dampers associated with each fan are interlocked with the fan such that they are fully open when the fan is operating and fully closed when the fan is stopped. These dampers fail to the open position on loss of control signal or control air. The fans discharge to the main auxiliary building exhaust system containing the HEPA filter bank. To ensure a path for the charcoal (and HEPA) filtered exhaust to the plant vent if the main exhaust fans are not operating, a fail-open damper is installed in a bypass circuit around the two main exhaust fans.

In addition to the main auxiliary building ventilation system (ABVS), the RHR, SI, CS, and charging pump motors are provided with additional cooling provisions when the pumps are operating. The SI and CS pump motors are located in an open area in the basement of the auxiliary building and share three heat exchangers cooled by service water. In 1992, service water to these heat exchangers was blanked off. The charging pumps and RHR pumps are located in individual rooms, with each room provided with two cooling units consisting of redundant fans, water-cooled heat exchangers, and ductwork for circulating the cooled air. The capacity of each charging pump cooling unit is sufficient to maintain acceptable room-ambient temperatures with the minimum number of pumps required for system operation in service.

The cooling units in the RHR pump pit are not required for the operation of the RHR pumps, even if both pumps are operating. In the event of a loss of offsite power, the ABVS main supply and exhaust fans would be inoperable. However, all other fans in the ABVS are supplied by emergency diesel power, including the pump cooling circuits for safety-related pump motors, as described above. Analysis has shown that the three levels of the auxiliary building and the

RHR pump pit would remain within acceptable limits when the outside air is at its maximum expected temperature and no cooling units are operating. Since the auxiliary building has a very large volume, a significant post-accident temperature increase is not expected, except in some local areas near hot piping and large motors.

The SFP area ventilation system is a part of the ABVS. The system serves to control airborne radioactivity in the SFP area during normal operating conditions. This is accomplished by directing air from the auxiliary building supply air unit across both the SFP and the decontamination pit to exhaust air ducts which are connected to the suction of the auxiliary building exhaust fan C. Exhaust air from the SFP water surface is drawn through roughing filters and, depending on system alignment, charcoal filters. Discharge from the auxiliary building exhaust fan C passes through HEPA filters, a main auxiliary building exhaust fan, and then out the plant vent. The nonsafety intermediate building ventilation system includes a supply fan that exhausts air from the intermediate building clean side to the intermediate building restricted area side. Two additional exhaust fans, which are located in the intermediate building restricted area side, draw ventilation air from various areas of both the clean and restricted area sides of the intermediate building and discharge to the auxiliary building discharge header plant vent duct. Ventilation air is provided to the intermediate building clean side through louvered outside air intakes, which are located in the east wall of the intermediate building. Additional ventilation air can be drawn into the intermediate building clean side from the turbine building through a louvered wall opening, which is installed in front of a rolling fire door in the fire barrier wall.

The standby auxiliary feedwater (SAFW) pump room cooling and heating system provides cooling and heating as required to maintain the pump room temperature within the design temperature range. This cooling and heating system is needed to provide an acceptable environment for the equipment in the pump room, which includes the two SAFW pumps and their electric drive motors. The SAFW room cooling system is capable of operation whenever the SAFW pumps are needed because the cooling system provides the air cooling required for continuous operation of the pump motors. A given cooling unit is automatically started whenever its corresponding SAFW pump is started. Because of its safety-related nature, the cooling system must remain functional during all modes of plant operation including the period during and after a safe shutdown earthquake.

The diesel generators are housed in adjacent but separate rooms, each of which is serviced by a safety-related ventilation system having two inlet fans supplying outside air. Each fan takes suction from a common header and discharges through separate ductwork, dampers, and discharge diffusers. One fan in each room discharges a supply of air directly on the instrument and control cabinets. Excess air is discharged to the outdoors through automatic, pressure-actuated room vents, backdraft dampers, and wall-mounted louvers. No refrigeration or service water air cooling is used.

The control room ventilation system is normally operated using a large percentage of recirculated air. The fresh air intake can be closed to control the intake of airborne activity if monitors indicate that such action is appropriate. The control room emergency air treatment system is designed to filter the atmosphere during periods when the control room is isolated and to maintain radiation levels at acceptable levels following a design-basis accident. This system circulates air from the control room, control room office, and kitchen through return air ductwork to a central air conditioning unit located in the air handling room. The air is drawn into the unit through roughing-type filters and either heated or cooled as required by electric heating or chilled water coils. Conditioned air is directed back to the rooms through a supply air ductwork system. The entire control room emergency zone air volume is turned over approximately 12 times every hour. During normal operation, fresh makeup air is admitted to this system through an intake louver located in the outside wall of the turbine building, with the amount varying between 0 to 25 percent of the unit flow rate, depending on outside air temperature. Pneumatically operated dampers can be positioned from the control room to isolate the fresh air intake and to place a separate charcoal filter unit in service. The charcoal filter unit includes both HEPA filters and 2-inch deep charcoal adsorbers for removing radioactive particulates and gaseous iodine from the control room atmosphere. Its capacity is approximately 25 percent of the system flow rate and the unit is installed in a normally isolated bypass circuit.

In the event of high radiation levels in the control room, the radiation instrumentation will automatically close the redundant dampers in the fresh air intake duct and the dampers in the return air duct to the turbine building, and open the damper in the charcoal filter unit inlet duct to allow 2000 cfm of the recirculation air to flow through the HEPA filters and charcoal adsorbers. This signal will also start a separate fan to provide flow through the charcoal filter unit. Until radioactivity in the control room atmosphere is reduced to a safe level, system flow will be in a closed cycle from the control room, with approximately 25 percent bypass flow through the charcoal filter unit, through the air conditioning unit, and back to the control room. The dampers can also be positioned to permit fresh air makeup to the system through the charcoal filter unit. Since all control room penetrations, including doors, are designed to high leak-tightness standards and the control room is maintained at essentially atmospheric pressure, the infiltration of contaminated air into the control room is very limited.

The control building ventilation system includes within its boundary battery and relay room ventilation. Supplemental heating and cooling to the battery rooms are provided by a nonseismic air conditioning unit, with associated service water piping, ventilation ductwork, electric heating coil, and fire dampers. The electric heating coil is seismically mounted in the heating, ventilation, and air conditioning unit discharge duct. The unit and associated ductwork and piping are designed to function during all plant modes. Although the overall design is nonseismic, the piping and ductwork are designed to maintain structural integrity during a design-basis earthquake. Each battery room has an alternating current (AC)-powered propeller exhaust fan that takes suction from the area to remove hydrogen gas generated by the batteries. Also, there is a separate emergency DC-powered ventilation system that is manually actuated in the event of low air flow in the ductwork of either of these battery room exhaust fans. The relay room contains two self-contained, water-cooled air cooling units that maintain a normal room temperature.

The TSC houses the computers and equipment, including emergency power supplies (diesel generators and batteries), necessary to provide the staff with technical support during an emergency. The TSC heating, ventilation, and air conditioning system maintains year-round occupancy comfort levels, provides personnel protection from airborne radiological contaminants, and maintains a positive pressure relative to the outside. Additionally, it provides cooling, heating, and ventilation required by special areas and equipment.

2.3.3.10.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.10 and UFSAR Sections 1.2, 6.4, 7.4, and 9.4.2 through 9.4.10 to determine whether there is reasonable assurance that the essential ventilation system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of license renewal. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

During the review of license renewal boundary drawing 33013-1256-LR, which depicts systems that provide ventilation to the TSC, the staff noted that only those SCs that serve the TSC diesel generator room, the TSC uninterruptible power supply, and the TSC battery room were shown to be within the scope of license renewal and subject to an AMR (see locations H1, 2, 3, 4; I1, 2, 3, 4, 5; and J1, 2, 3, 4). Section 1.2.3.7 of the UFSAR states that the TSC "is located on the second floor of the all-volatile treatment building and houses the computers and equipment, including emergency power supplies (diesel generators and batteries), necessary to provide the staff technical support during an emergency event."

In order for the staff to confirm that all TSC ventilation SCs serving an intended function meeting the scoping criteria of 10 CFR 54.4(a) have been considered, the staff requested, in a letter dated March 21, 2003, that the applicant identify all equipment which relies on the ventilation SCs considered within scope and justify the omission from scope of those ventilation SCs serving other areas of the TSC (RAI 2.3.3.10-1).

By letter dated May 13, 2003, the applicant responded that not all ventilation SCs serving the TSC are relied upon for safe shutdown in the CLB. The only ventilation SCs included in the scope of license renewal are those used for post-fire safe shutdown activities, a 10 CFR 54.4(a)(3) function. Regarding equipment that relies on these ventilation SCs, the applicant identified the TSC diesel generator located in the TSC diesel generator room, and a battery charger located in the TSC battery room. The diesel generator can be used to supply the battery charger, thus supporting vital DC power for long-term recovery following certain fire scenarios. (These components are addressed in Section 2.3.3.8 of the LRA.)

The staff considers the applicant's response to RAI 2.3.3.10-1 to be acceptable because information was provided that clarified that all TSC ventilation SCs within the scope of license renewal and subject to an AMR have been identified in the LRA, in accordance with 10 CFR 54.4 and 54.21(a)(1). No omissions were found upon further review.

Section 7.4 of the UFSAR, which addresses the alternative shutdown system, states that in case of fire within the control room fire zone, the control room may be evacuated and the plant shut down from alternative shutdown stations located in other areas of the plant. However, during its review, the staff noted that the systems providing ventilation to the alternative shutdown stations and controls were not addressed in either the LRA or the UFSAR.

By letter dated March 21, 2003, the staff asked that the applicant identify the SCs used to provide ventilation to the alternative shutdown stations that are within the scope of license renewal and subject to an AMR, in accordance with 10 CFR 54.4(a)(1) and (a)(2). The staff also requested that justification be provided for excluding any ventilation SCs that were not considered to be within scope (RAI 2.3.3.10-2).

By letter dated May 23, 2003, the applicant responded that all ventilation SCs required to support the functioning of equipment used for safe shutdown have been identified in the LRA and are within the scope of license renewal and subject to an AMR. These include SCs that support operation of the EDGs, the TSC diesel generator and battery charger, and the SAFW pumps. The applicant also noted that the auxiliary building local indicating panel and the intermediate building local indicating panel, which are used to support safe shutdown, do not require ventilation to function because they are located in areas where ambient temperatures will not rise to a level at which their operation would be affected.

The staff considers the applicant's response to RAI 2.3.3.10-2 to be acceptable on the basis that clarification was provided that identified those ventilation SCs that are within the scope of license renewal and subject to an AMR, and the exclusion from scope of other ventilation SCs was justified.

During the review of license renewal boundary drawing 33013-1869-LR, which depicts systems that provide ventilation to the residual heat removal, containment spray, charging, safety injection, and standby auxiliary feedwater (AFW) pumps, the staff noted that only those SCs that serve the standby AFW pumps were shown to be within the scope of license renewal and subject to an AMR.

Two redundant cooling units each are provided for both the RHR pump pit and the charging pump room. Three cooling units, headered into common ductwork, are provided for the safety injection and containment spray pumps. A separate cooling unit is provided for each of the two standby AFW pumps. LRA Section 2.3.3.10 states that the fans for all of these cooling units are supplied by emergency diesel power.

All of the pumps listed above are safety-related and are within the scope of license renewal, in accordance with 10 CFR 54.4(a)(1), items (i) and (ii). The systems providing ventilation to the areas housing these pumps and associated pump motors have the function of maintaining an acceptable environment for operation of these components under accident conditions. Therefore, the staff considers these ventilation systems to be within the license renewal boundary. By letter dated March 21, 2003, the staff requested that the applicant provide justification for excluding the ventilation systems servicing the RHR, CS, charging, and SI pumps from the scope of license renewal. If the justification is based on analysis, the applicant should summarize the assumptions made and the resulting conclusions for each of these pumps (RAI 2.3.3.10-3).

By letter dated May 13, 2003, the applicant responded that the RHR, SI, and CS pump motors have been analyzed to operate with no ventilation required following a design-basis LOCA. This analysis, documented in ALTRAN Technical Report 99124TR001, computed peak temperatures in various areas of the auxiliary building following a design-basis LOCA. Based on these peak temperatures, the EQ of all safety-related equipment in the auxiliary building, which includes these pump motors, was reviewed. This review concluded that these motors were still capable of performing their safety-related functions without ventilation. The magnitude of peak temperatures, as well as their short duration, resulted in a negligible decrease in qualified life. On this basis, the applicant concluded that the cooling units serving the areas housing the RHR, SI, and CS pumps did not support a safety-related function and therefore are not within the scope of license renewal nor are they subject to an AMR.

The applicant also stated that the charging pumps are not required to operate following a LOCA but need only survive the environmental effects of a steam heating line break in the auxiliary building (with a calculated temperature of 150 °F). Since normal operation of these pumps produces a temperature in the motor windings greater than the 150 °F environment, the charging pump motors were removed from the Ginna EQ master list. Accordingly, the two cooling units serving the charging pump room do not support a safety-related function and therefore are not within the scope of license renewal nor are they subject to an AMR.

The staff considers the applicant's response to RAI 2.3.3.10-3 to be acceptable on the basis that justification was provided for excluding those systems providing ventilation to the RHR, CS, charging, and SI pumps from the scope of license renewal. All ventilation SCs within the scope of license renewal and subject to an AMR have been identified in the LRA, in accordance with 10 CFR 54.4 and 54.21(a)(1). No omissions were found upon further review.

Section 9.4.9 of the UFSAR states that the ESF ventilation and cooling systems include those systems that service equipment required either following an accident or to ensure safe plant shutdown. Included on the provided list of equipment and/or areas serviced by these systems are the relay room and battery rooms, located in the control building. However, during its review of license renewal boundary drawing 33013-1868-LR, the staff found that the ventilation SCs servicing the relay room and the two battery rooms were excluded from the scope of license renewal. By letter dated March 21, 2003, the staff requested that the applicant justify the exclusion of the ventilation SCs servicing these rooms (RAI 2.3.3.10-4).

By letter dated June 10, 2003, the applicant responded that although the battery and relay rooms contain SSCs that perform license renewal intended functions, the ventilation systems for these rooms do not have a license renewal intended function. These ventilation systems are not safety-related, as described in UFSAR Section 3.11.3.5. Testing and analysis have demonstrated that the post-accident temperature rise in these rooms is not rapid, and operator response measures, such as opening doors and using portable air units or fans, would maintain room temperatures at acceptable levels, even if the nonsafety air conditioning units provided for these rooms did not operate. Also, as stated in UFSAR Section 8.1.4.5.2, expected room temperatures during an SBO were evaluated, per Devonrue August 1990 and December 15, 1993, analyses. This evaluation determined that the equipment would remain operable even with a loss of ventilation.

The staff considers the applicant's response to RAI 2.3.3.10-4 to be acceptable because it clarified the exclusion of the ventilation SCs servicing the relay room and the two battery rooms from the scope of license renewal. All ventilation SCs within the scope of license renewal and subject to an AMR have been identified in the LRA, in accordance with 10 CFR 54.4 and 54.21(a)(1).

During the review of the LRA and associated license renewal boundary drawings, the staff identified two additional items, each applicable to both the containment ventilation and essential ventilation systems, which needed clarification by the applicant.

The first item concerned the symbol for "air opening" appearing at various air intakes and exhausts in many of the boundary drawings. (This symbol is shown in the symbol legend, drawing 33013-2242,3-LR, location H4.) Many of these air openings are highlighted to identify them as being within the scope of license renewal and subject to an AMR. However, because a different symbol was used for "louvers" in the drawings, the physical nature of air openings (e.g., screens and grillwork) was not clear to the staff. Furthermore, air openings were not listed as a component group in LRA Tables 2.3.3-9 and 2.3.3-10.

By letter dated March 21, 2003, the staff requested that the applicant describe these air openings and justify their exclusion from the above-mentioned tables (RAI Generic HVAC-1).

By letter dated May 13, 2003, the applicant responded that all air openings identified as being within the scope of license renewal, regardless of design, are included in Tables 2.3.3-9 and 2.3.3-10 under the component group "ventilation ductwork."

The staff considers the applicant's response to RAI Generic HVAC-1 to be acceptable on the basis that clarification was provided confirming that no air openings identified as being within scope were excluded from LRA Tables 2.3.3-9 and 2.3.3-10.

The second item concerns the cooling coils and heating coils shown to be within the scope of license renewal on the boundary drawings for the containment ventilation and essential ventilation systems. Cooling coils and heating coils are listed as component groups in LRA Tables 2.3.3-9 and 2.3.3-10, with pressure boundary as the only intended function specified.

Heat transfer, however, is not specified as an intended function for these coils. "Heat exchangers" are also listed as a separate component group in LRA Tables 2.3.3-9 and 2.3.3-10 with the specified intended functions of both heat transfer and pressure boundary.

The staff considers both cooling coils and heating coils to be heat exchangers. However, cooling and heating coils appear to be the only heat exchangers shown to be within scope on the license renewal boundary drawings for the containment ventilation and essential ventilation systems. Therefore, it was not clear to the staff what differentiates the "heat exchangers" component group from the “cooling coils” and “heating coils” component groups in LRA Tables 2.3.3-9 and 2.3.3-10.

By letter dated March 21, 2003, the staff requested that the applicant identify any heat exchangers, other than cooling coils and heating coils, that are within the scope of license renewal and have not been identified on the license renewal boundary drawings, and explain why heat transfer is not listed as an intended function for the cooling and heating coils (RAI Generic HVAC-2).

By letter dated May 21, 2003, the applicant explained that the symbols assigned to heat exchangers in the symbol legend did not appear on the license renewal boundary drawings because all in-scope heat exchangers were considered subcomponents of the cooling and heating coils and thus were not illustrated. The staff considers the applicant’s response to RAI Generic HVAC-2 to be acceptable because the applicant explained the absence of the symbols for heat exchangers on the license renewal boundary drawings.

Additionally, the applicant responded that “the specific cooling/heating coils and heat exchangers in question only have a pressure boundary intended function, that is their heat transfer function is not credited in the current licensing basis.” However, the staff noted that under the component group “heat exchangers” in LRA Tables 2.3.3-9 and 2.3.3-10, both pressure boundary and heat transfer are listed as intended functions. This appears to contradict the above response and was discussed with the applicant. The applicant stated that the tables were in error and committed to making the necessary corrections. This was Confirmatory Item 2.3.3.10-1.

By letter dated December 9, 2003, the applicant responded that both pressure boundary and heat transfer are intended functions for the specified cooling/heating coils and heat exchangers as specified in LRA Tables 2.3.3-9 and 2.3.3-10. The staff considers the applicant’s response to Confirmatory Item 2.3.3.10-1 to be acceptable because the heat transfer function is listed as an intended function. This closes Confirmatory Item 2.3.3.10-1.

2.3.3.10.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant’s responses to the staff’s RAIs to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. On the basis of this review, the staff concludes that the applicant has appropriately identified those portions of the essential ventilation system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified those portions of the essential ventilation system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.11 Cranes, Hoists, and Lifting Devices

2.3.3.11.1 Summary of Technical Information in the Application

The cranes, hoists, and lifting devices equipment group consists of overhead load handling systems considered to contain nonsafety-related components whose failure could affect a safety function, specifically a heavy load drop that could result in damage to safe shutdown equipment. The components in this category were identified in the Ginna response to NUREG-0612, "Control of Heavy Loads." The principal components of the cranes, hoists, and lifting devices equipment group include the reactor head lifting device, the reactor internals lifting device, and the load carrying elements of the containment main crane, the auxiliary building main crane, and the SFP and containment refueling bridge cranes, as well as selected jib and monorail hoists. Included are cables, hooks, and the moving load-bearing elements. The crane rails and supports that interface with building structural members are evaluated within the building that contains them. The majority of the plant crane hoists and lifting devices are excluded from this category because of administrative controls over their use or because their distance from safety-related equipment precludes the possibility of damaging safe shutdown equipment, as documented in NUREG-0612.

2.3.3.11.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.11 and UFSAR Section 9.1 to determine whether there is reasonable assurance that the cranes, hoists, and lifting devices within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1). In the performance of its review, the staff selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of license renewal. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted. During its review of LRA Section 2.3.3.11, the staff determined that additional information was needed to complete its review. By letter dated March 21, 2003, the staff asked the applicant to identify the specific component types and locations that are within the scope of license renewal and subject to an AMR (RAI 2.3.3.11-1).

In its response dated May 23, 2003, the applicant stated that the specific components of the cranes, hoists, and lifting devices equipment group are the containment main overhead crane, containment 3-ton jib, containment fuel manipulator crane, containment 10-ton jib crane, containment 2-ton jib, auxiliary building main overhead crane, auxiliary building SFP bridge crane, auxiliary building RHR pumps monorail, intermediate building 3-ton monorail on the upper level, and the screenhouse overhead crane. This information was provided in the applicant's response to NUREG-0612, dated March 2, 1983. The staff finds the applicant's response to be acceptable as it identified the specific components that are included in the cranes, hoists, and lifting devices equipment group.

By letter dated March 21, 2003, the staff asked the applicant to list the structures and/or subcomponents of the cranes, hoists, lifting devices, etc., that are within the scope of license renewal and subject to an AMR (RAI 2.3.3.11-2). Listing "crane" as the SCs subject to an AMR does not satisfy the requirement of 10 CFR 54.21(a)(1) because an entire crane is not subject to an AMR.

By letter dated May 13, 2003, the applicant responded that, as noted in LRA Section 2.3.3.11, the component group “crane” includes cables, hooks, and moving load-bearing elements (bridges and trolleys). Crane rails are evaluated as part of the structures that contain them. The staff considers the applicant’s response to RAI 2.3.3.11-2 to be acceptable because it identified the subcomponents of the component group “crane” that are subject to an AMR.

2.3.3.11.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant’s responses to the staff’s RAIs to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified the components of cranes, hoists, and lifting devices that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified the components of the cranes, hoists, and lifting devices that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.12 Treated Water

2.3.3.12.1 Summary of Technical Information in the Application

The treated water system comprises several secondary plant subsystems including demineralized water production, domestic (potable) water, secondary water chemical treatment, and nonradioactive liquid waste disposal (floor drains, secondary sample effluents, etc.). The treated water subsystems are nonsafety auxiliary systems that support the functionality of other process systems. The treated water system contains floor drains and equipment whose failure could prevent the satisfactory accomplishment of a safety function (flood mitigation and backflow of oil through floor drain prevention).

The principal components of the treated water system are pumps, tanks, ion exchange vessels and the piping, hoses, and valves necessary for the subsystems to function. The primary water treatment system or mobile demineralizer trucks process domestic water to provide demineralized water to the reactor makeup water tank, the component cooling water surge tank, the condensate storage tanks, and various locations throughout the plant via a piping distribution network. The all-volatile treatment (AVT) chemistry system uses chemical addition and ion exchange to treat condensate water in order to reduce the corrosion of equipment in the secondary system and minimize the fouling of heat transfer surfaces. The AVT regeneration wastes are collected in neutralization tanks and sampled to determine disposition methods. The catalytic oxygen removal system reduces condensate-dissolved oxygen by mixing hydrogen with the condensate and reducing the free oxygen to water by exposure of the mixture to a metal catalyst surface. The secondary plant equipment and floor drains serve to route leakage from equipment and compartments to provide proper control of leakage, prevent uncontrolled communication between areas as necessary, and allow monitoring of leakage prior to disposition. Where drains from safety-related areas are tied into drains from areas that contain a large quantity of flammable liquid, backflow protection is provided to prevent possible spread of a liquid fire via the drain system. An underground retention tank is the collection point for the various building floor and equipment drains. It retains these effluents for sampling and treatment prior to discharging them into the circulating water discharge.

2.3.3.12.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.12 and UFSAR Sections 9.2.3, 9.5.1.2.4.5, and 10.7.7 to determine whether there is reasonable assurance that the treated water system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of license renewal. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

In a letter dated March 21, 2003, the staff requested that the applicant explain why all of the treated water system discharge piping comprising the flowpaths to a retention tank or the discharge canal is not subject to an AMR, or describe how the maximum flood inventory is accommodated (RAI 2.3.3.12-1). License renewal boundary drawing 33013-2681-LR shows six sump pumps and connecting piping and valves as being subject to an AMR. The six pumps are in DG room “A” (location A6), DG room “B” (location A8), the control building ventilation room (location F6), and battery room “A” (location F7). The DG room vault sump pumps discharge to piping that is subject to an AMR; however, the scoping boundary for this piping does not extend completely to the discharge canal, the final depository for the discharge flow. The sumps containing the diesel generator “B” floor drain sump pump and the battery room “A” floor drain sump pump gravity drain through ball check valves. The discharge piping subject to an AMR extends only to the floor drain outside of the subject room. It is not clear from the information provided in license renewal boundary drawing 33013-2681 where the three sump pumps, PWT28, PWT29, and PWT30 (at locations B7, E7, and E6, respectively), discharge to, as the sumps all appear to be gravity drained. In each of these cases, the intended system function of preventing flooding would appear to require that the complete discharge piping flowpath, up to the final discharge point, be subject to an AMR. An exception could occur where the capacity of an interim storage location is sufficient to hold the maximum flood inventory.

In a letter dated May 13, 2003, the applicant responded that the capacity of the interim storage volume can be viewed as infinite. After initial construction, the sump water boxes were modified to prevent potential backflow of oil into spaces containing safety-related equipment. In some instances, the modification consisted of installing a baffle, horizontally bisecting the water box. The sump pumps move the water that might collect on top of the baffle, through a check valve, to the bottom of the water boxes where the fluid flows by gravity through the drain header. The check valves and baffles prevent fluids from being forced from the common drains back into the space.

The applicant reasoned that the entire treated water system discharge path is not subject to AMR lies in the configuration of the flowpath. The drainage portion of the system outside the areas of concern is not a closed system. Numerous water boxes that are open to the atmosphere exist in the drain system. Should the path to the retention tank be unavailable, the water volume simply overspills these water boxes, with ultimate dewatering occurring through flow across the turbine building floor into the yard. Thus, the treated water system discharge piping flowpaths are not subject to an AMR in their entirety; only the piping and components that drain water from, or prevent water from backing up into, rooms that contain safety-related equipment are within the scope of license renewal. During the AMP audit, the staff verified that the discharge piping is not a closed system and that none of the accessible piping appeared damaged. The staff also verified that the water boxes are open to the atmosphere and any overspills would flow across the turbine building floor thus providing a virtual infinite storage volume.

Location E8 of license renewal boundary drawing 33013-2681,3-LR shows the floor drain line for battery room “B” as not being within the scope of license renewal. However, at location E7 of this same drawing, the drainage line from battery room “A” is shown as being within scope. In a letter dated March 21, 2003, the staff requested that the applicant document the basis for concluding that the floor drain line for battery room “B” is not within the scope of license renewal, so that the staff may verify compliance with 10 CFR 54.4(a) (RAI 2.3.3.12-2).

By letter dated May 13, 2003, the applicant responded that the referenced license renewal drawing inadequately depicts the “B” battery room drainage configuration. The room does not contain a floor drain; rather, the floor is sloped to provide gravity drainage to battery room “A.” The configuration of the “A” battery room drainage prevents the backflow of oil or combustible liquids into the battery rooms from external sources. There are no fluid systems in the battery rooms that could be internal flood sources. Therefore, the battery room “B” drainage has no license renewal intended function and is not within scope. The staff determined the applicant’s response was acceptable because it clarified that the battery room “B” drainage does not perform a license renewal intended function and therefore is not included within scope.

2.3.3.12.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant’s responses to the staff’s RAIs to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. On the basis of this review, the staff concludes that the applicant has appropriately identified those portions of the treated water system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified those portions of the treated water system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.13 Radiation Monitoring—Mechanical

2.3.3.13.1 Summary of Technical Information in the Application

The function of the radiation monitoring system is to detect any plant problem that may lead to a radiation hazard and/or release of radioactivity to the environment. The system also warns the operators of this hazard so that appropriate actions may be taken. To accomplish this function, the system utilizes both area and process radiation monitors. Some radiation monitors sense parameters and generate signals that interface with ESF actuation (e.g., containment isolation) or are used to monitor for reactor coolant leakage. Others provide automatic nonsafety process system control functions as a result of a high alarm. Radiation monitors also ensure control room habitability by generating an isolation signal used to secure the control room ventilation envelope. The control room emergency air treatment system also contains NNS toxic gas detection that electrically interfaces with the radiation monitoring system's control room ventilation isolation signal. These toxic gas monitors are included within the evaluation boundary of the radiation monitoring system as nonsafety components whose failure could prevent the satisfactory accomplishment of a safety-related function. The radiation monitoring system also contains post-accident monitoring instrumentation that is environmentally qualified. The principal components of the radiation monitoring system include area monitors; process monitors; system-level particulate, iodine, and noble gas monitors; data acquisition modules (DAM); computer interface and terminal equipment; toxic gas detectors; and the pumps, valves, and essential ductwork and piping necessary for their functioning. Section 11.5 of UFSAR provides a detailed description of all the radiation monitors and their functions.

2.3.3.13.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.13 and UFSAR Sections 6.4.2.2.3, 6.4.5, 11.5, and 12.3.4 to determine whether there is reasonable assurance that the radiation monitoring system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of license renewal. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

During its review of LRA Section 2.3.3.13, the staff determined that additional information regarding the components on the containment ventilation process radiation monitor skid was needed to complete its review. These components were identified in license renewal boundary drawing 33013-1866-LR, location G11, as being outside the scope of license renewal. The staff believes that these components are passive and long lived and perform an intended function of providing process conditions and generating signals for reactor trip and ESF actuation, and therefore should be subject to an AMR. Monitors included on the skid are the containment gas monitor, containment iodine monitor, and the containment particulate monitor.

Piping and associated fittings and valves that transport the material to be monitored from the containment are subject to an AMR only up to the containment boundary.

The piping that continues inside containment also appears to be needed for the system to perform its intended function. By letter dated March 21, 2003, the staff requested that the applicant clarify whether these components were subject to an AMR or justify their exclusion from the scope of license renewal (RAI 2.3.3.13-1).

By letter dated May 13, 2003, the applicant responded that the piping that continues inside containment is not in scope because it does not provide an intended containment isolation boundary function. Isolation occurs outside of containment. The portion of piping, valve, and components leading to the containment gas, iodine, and particulate monitor skid was conservatively included in the scope of license renewal, although as stated in UFSAR Section 6.2.4.3, the containment ventilation isolation signal serves as a backup to the containment isolation signal and is not specifically credited in the accident analysis.

The staff finds the applicant's clarification that containment isolation is the only intended function of the radiation monitoring skid equipment acceptable. On the basis of this additional information, the staff concurs that the components on the containment ventilation process radiation monitor skid are not in the scope of license renewal and are not subject to an AMR.

During its review of LRA Section 2.3.3.13, the staff determined that additional information was needed regarding the components on the control room radiation monitor skid in order to complete its review. License renewal boundary drawing 33013-1867-LR shows the control room radiation monitor skid. The only components shown on this skid are radiation monitors. By letter dated March 21, 2003, the staff requested that the applicant confirm that the only components on these skids are the radiation monitors. If this was not the case, the applicant was requested to identify the other components and justify the exclusion of these components from the scope of license renewal and from being subject to an AMR (RAI 2.3.3.13-2).

In a letter dated May 13, 2003, the applicant responded that the radiation monitoring system includes specific components on the control room radiation monitor skid such as valves, pumps, piping, tubing, flow meter, filter housings, and detectors which were evaluated and determined to require an AMR. Drawing 33013-1867-LR shows a box around RE-36/37/38, which represents the skid. The applicant confirmed that all components on the skid are subject to an AMR. During the AMP audit, the staff walked down the control room radiation monitor skid and verified that the skid included valves, flow meter, filter housing, and detectors, and verified that the identified components were included in the applicant's review tool (could be traced back to the LRA) and are subject to an AMR.

By letter dated March 21, 2003, the staff requested several clarifications from the applicant regarding the basis for including or excluding certain SSCs from the scope of license renewal and/or being subject to an AMR (RAI 2.3.3.13-3).

License renewal boundary drawing 33013-1866-LR, location H9, shows components FT-112, PT-111, and DPS-110 as requiring an AMR. Since these components did not appear to serve a license renewal intended function, the staff questioned whether footnote 1 of Table 2.3.3-13 on page 2-169 of the LRA applies in this instance (RAI 2.3.3.13-3a). This footnote states that selected instruments were conservatively included within the scope of license renewal, with consideration given to the consequences of an instrument housing pressure boundary failure. Where an instrument is unisolable from a pressure source and is of sufficient size that a system function would be degraded should the pressure boundary fail, that instrument is included in the scope of license renewal.

By letter dated May 23, 2003, the applicant responded that including FT-112, PT-111, and DPS-110 as within scope was a typographical error. These components are not in the scope of license renewal. The staff finds this response to be acceptable, on the basis that these components do not serve a license renewal intended function.

The staff also requested clarification regarding apparent differences between the list of license renewal drawings shown on page 2-168 of the LRA and the information on the drawings themselves. According to information provided by the applicant in the LRA, SSCs referenced in the application but not subject to AMR, have drawing and UFSAR references indicated. However, those references are not hypertext linked. The staff incorrectly interpreted this information to mean that drawings that are hypertext linked in a given section show components that are within the scope of license renewal and subject to an AMR. In RAI 2.3.3.13-3b, the staff cited instances where no components on highlighted drawings in the list on page 2-168 were shown as being within scope and subject to an AMR, even though the drawings indicated that the components performed a safety-significant function. For example, on drawing 133013-2287-LR, note 2 states that RE-21 performs a safety-significant detection function. However, neither RE-21 nor the connecting piping was shown as requiring an AMR. On drawing 33013-1278, 2-LR, note 3 states that RE-19 and RM-19 combine to perform a safety-significant detection function, yet neither of these is shown as requiring an AMR.

By letter dated May 23, 2003, the applicant responded by explaining how the drawings indicating which SSCs require an AMR interact with, and are related to, the lists of drawings associated with systems such as those on LRA page 2-168. The color-coded information on the drawing indicates the SSCs that require an AMR. With respect to notes and flags on drawings that indicate safety-significant functions, as detailed in LRA Section 2.1.4 and as clarified in the applicant’s response to RAI 2.3-1, the safety-significant (augmented quality) classification is not in and of itself a basis for inclusion within the scope of license renewal. Thus both the lists of drawings and the drawings themselves are correct, but the drawings that indicate which SSCs require an AMR are generally more useful. The staff finds the applicant’s response to be acceptable on the basis that the explanation clarified how the license renewal drawings and LRA text interact to identify components that are subject to an AMR.

2.3.3.13.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant’s responses to the staffs RAIs to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. On the basis of this review, the staff concludes that the applicant has appropriately identified those portions of the radiation monitoring system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified those portions of the radiation monitoring system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.14 Circulating Water

2.3.3.14.1 Summary of Technical Information in the Application

Circulating water (CW) is a nonseismic system designed to provide a reliable supply of water, regardless of weather or lake conditions, to the suction of the screenhouse pumps. The water supplied is used to condense the steam exhausted from the low-pressure turbines. Those portions of the CW system that support the delivery of lake water sufficient for the use of SW and fire water pumps are evaluated within the SW system. Those portions of the CW system that provide CW flood detection are evaluated within the reactor protection system. Consequently, within the system evaluation boundary, no components perform license renewal intended functions and the CW system is not within the scope of license renewal.

The principal components of the CW system are the CW pumps, traveling screens, chlorine addition tanks and pumps, and the essential piping and valves. The system includes an intake structure specially designed to minimize the possibility of clogging, an inlet tunnel, four traveling screens, two circulating water pumps, and a discharge canal. The intake tunnel and the intake tunnel bypass (loss of lake valve and bypass piping) are evaluated within the SW system. The intake is designed to withstand, without loss of function, ground accelerations of 0.2 g, acting in the vertical and horizontal planes simultaneously. The probability of water stoppage due to plugging of the inlet has been reduced to an extremely low value by incorporating design features in the system. Before the inlet plenum water reaches the pump suctions, the water passes through the four parallel traveling screens. Service water pump discharge is used to periodically flush the debris off the screens into a collecting trough where it is carried away.

2.3.3.14.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.14 and UFSAR Section 10.6 to determine whether there is reasonable assurance that the CW system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of license renewal. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

As stated in LRA Section 2.3.3.14, those portions of the CW system that provide CW flood detection are evaluated within the reactor protection system. Also, those portions of the CW system that support the delivery of lake water sufficient for the use of the SW and fire water pumps are evaluated within the SW system. In part, 10 CFR 54.21(a)(1) states that components and their intended functions that meet the scoping criteria of 10 CFR 54.4(a) and are subject to an AMR must be identified and listed so that their aging effects can be adequately managed consistent with the CLB. To confirm that SSCs with intended functions described in the UFSAR using traditional (i.e., CLB) nomenclature have been captured in the license renewal process, the staff needs to identify components from out-of-scope systems that were evaluated as part of the in-scope systems in the information provided in the LRA and the license renewal boundary drawings. In a letter dated March 21, 2003, as part of F-RAI 2.2-1, the staff requested that the applicant identify the components (identified above) from out-of-scope systems in the tables contained in LRA Section 2.3. The staff requested that the applicant identify the components of the CW system that perform intended functions that are evaluated with the SW and reactor protection systems, the intended functions they perform, and if they are subject to an AMR.

In a letter dated June 10, 2003, the applicant responded that the CW system and the SW system share certain components within the scope of license renewal. In the application, the emergency intake from the discharge canal, as well as the combined SW/CW discharge piping, is included in the SW system boundary. The affected components are pipe and valve bodies as listed in Table 2.3.3-5.

The staff reviewed the applicant's response to RAI 2.2-1 regarding the evaluation of those portions of the CW system that support the delivery of lake water sufficient for the use of the SW and fire water pumps that are evaluated within the SW system. The staff finds the applicant's response to be acceptable on the basis that the applicant has adequately identified the components of the CW system that are subject to AMR.

2.3.3.14.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's responses to the staff's RAI to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified those portions of the CW system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified those portions of the CW system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.15 Chilled Water

2.3.3.15.1 Summary of Technical Information in the Application

The chilled water system supports normal habitability and equipment reliability by maintaining control room and office space temperature within acceptable bounds during normal operating conditions. Accordingly, components within the chilled water system do not perform any license renewal intended functions, and this system is not within the scope of license renewal. The principal components of the chilled water system are the chilled water pumps, the chiller units, a surge tank, and essential piping and valves. The chilled water system supplies chilled water to the control room heating, ventilation, and air conditioning (HVAC) unit and various cooling coils within individual service building HVAC units. Service water removes heat from the chilled water system.

2.3.3.15.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.15 and UFSAR Section 6.4.2.2 to determine whether there is reasonable assurance that the chilled water system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of license renewal. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

During its review of LRA Section 2.3.3.15, the staff determined that additional information was needed to complete its review. By letter dated March 21, 2003, the staff identified that the chilled water cooling coil for the control room air handling unit shown at location A9 on license renewal boundary drawing 33013-1867-LR is within the scope of license renewal, while a similar cooling coil at location J7 on license renewal boundary drawing 33013-1920 is shown as not being within the scope of license renewal. The applicant was asked to clarify whether this cooling coil is within the scope of license renewal, in accordance with 10 CFR 54.4(a) (RAI 2.3.3.15-1).

By letter dated May 13, 2003, the applicant responded that there is a typographical error on the license renewal drawing 33013-1867-LR. The control room air handling unit housing is in scope, not the coils. The letters should have been colored black on license renewal boundary drawing 33013-1867 at location A9. The housing is included for its pressure boundary function. There are no components on drawing 33013-1920 that are within the scope of license renewal. The staff considers the applicant's response to be acceptable, on the basis that the chilling coils do not perform an intended function as defined by the Rule.

2.3.3.15.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's response to the staff's RAI to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified those portions of the chilled water system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified those portions of the chilled water system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.16 Fuel Handling

2.3.3.16.1 Summary of Technical Information in the Application

The applicant did not consider the fuel handling system to be within the scope of license renewal. This system provides a safe and effective means for transporting and handling reactor fuel from the time the fuel reaches the plant in an unirradiated condition until it is placed in the SFP racks to await final long-term storage. The fuel handling system boundary does not include any cranes, hoists, or lifting devices categorized under NUREG-0612, "Control of Heavy Loads." Cranes, new and spent fuel storage racks, and the SFP and cavity liners are evaluated separately.

The principal components of the fuel handling system include the new fuel elevator, the underwater air motor driven fuel conveyor car, the pneumatic control assembly equipment for the fuel manipulator cranes, fuel and reactor internals handling tools, control equipment for safety interlocks, and essential valves and air tubing.

Special precautions are taken in all fuel handling operations to minimize the possibility of damage to fuel assemblies during transport to and from the SFP and during installation in the reactor. All handling operations on irradiated fuel are conducted underwater. The handling tools used in the fuel handling operations are conservatively designed, and the associated devices are of a fail-safe design.

In the fuel storage area, administrative controls and geometric constraints ensure that the fuel assemblies are spaced in a pattern that prevents a criticality accident. Also, crane interlocks and administrative controls prevent carrying heavy objects, such as a spent fuel transfer cask, over the fuel assemblies in the storage racks. As an additional administrative control, only one fuel assembly can be handled at a given time over storage racks containing spent fuel. The motions of the cranes that move the fuel assemblies are limited to a relatively low maximum speed. Caution is exercised during fuel handling to prevent fuel assemblies from striking other fuel assemblies or structures in the containment or SFP. The fuel handling equipment suspends fuel assemblies in the vertical position during fuel movements, except when they are moved through the transport tube.

2.3.3.16.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.16 and UFSAR Sections 1.8, 9.1, and 15.7 to determine whether there is reasonable assurance that the fuel handling system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of license renewal. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

During its review of LRA Section 2.3.3.11, the staff determined that additional information was needed to complete its review. By letter dated March 21, 2003, the staff asked the applicant to identify the components of the fuel handling system that make up the fuel and reactor internals handling tools and control equipment for safety interlocks (including housings and support structures) (RAI 2.3.3.16-1). The applicant was asked to discuss whether the fail-safe features of these tools could be compromised by wear, impact damage, or other age-related degradation mechanisms. If so, the staff requested justification of the exclusion of this equipment from the scope of license renewal and from being subject to an AMR.

By letter dated May 13, 2003, the applicant responded that components within the fuel handling system that have intended functions are evaluated with the cranes, hoists, and lifting devices system, LRA Section 2.3.3.11. Technical specification surveillance requirement TSR 3.9.3.1 verifies that the refueling manipulator crane interlocks are operable before each refueling operation. The balance of the components in the fuel handling system do not perform any license renewal intended functions. The staff finds the applicant’s response to be acceptable as it clarifies that the equipment in the fuel handling system does not perform a license renewal intended function.

2.3.3.16.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant’s response to the staff’s RAI to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified those portions of the fuel handling system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified those portions of the fuel handling system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.17 Plant Sampling

2.3.3.17.1 Summary of Technical Information in the Application

The plant sampling system provides representative nuclear process system (e.g., primary coolant) and nonnuclear, nonradioactive process system (e.g., condensate) samples for laboratory analysis. Equipment for sampling secondary and nonradioactive fluids is separated from the equipment provided for reactor coolant samples. No components within the plant sampling system evaluation boundary perform license renewal intended functions, and this system is considered not to be within the scope of license renewal. Leakage and drainage resulting from the radioactive sampling operations are collected and drained to tanks located in the waste disposal system. Components associated with containment isolation are evaluated with the containment isolation system. Safety-related interface components (e.g., heat exchangers) are evaluated within the system that is used to remove heat. The principal components of the plant sampling systems include heat exchangers, pumps, tanks, and the essential piping and valves. The two types of samples obtained by the nuclear process sampling portion of the system are (1) high-temperature, high-pressure RCS and steam generator blowdown samples which originate inside the reactor containment, and (2) low-temperature, low-pressure samples from the chemical and volume control and auxiliary coolant systems. Typical information obtained from the primary coolant analyses includes reactor coolant boron and chloride concentrations; fission product radioactivity level; corrosion product concentration and chemical additive concentrations; and oxygen, hydrogen, and fission gas content. The nuclear process portion of the sample system also includes a post-accident sampling system. The post-accident sampling system is designed to allow the station to obtain and analyze reactor coolant, containment air, and containment sump samples within 3 hours after the decision is made to sample.

The post-accident sampling system also permits routine sampling of these process streams. In-line chemical instrumentation is provided in a liquid and gas sample panel that remotely determines important chemical parameters of the reactor coolant, containment air, and containment sump A. In addition, the liquid and gas sample panel enables acquisition of both diluted and undiluted grab samples of the reactor coolant and containment air for isotopic analysis in the counting lab.

The nonnuclear or secondary sampling system is provided with a number of sampling points. In-line analyzers are provided for selected parameters to allow continuous information useful in evaluating secondary conditions and in developing corrective actions when required. Major elements of the nonnuclear process sampling portion of the system include steam generator blowdown sampling, main condenser hotwell sampling, condensate sampling, feedwater sampling, main steam sampling, and heater drain tank sampling. Typical information obtained from secondary sampling includes pH, conductivity, chlorides, sulfate, sodium, ethanolamine, and ammonia.

2.3.3.17.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.17 and UFSAR Section 9.3.2 to determine whether there is reasonable assurance that the plant sampling system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of license renewal. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

As stated in LRA Section 2.3.3.17, those portions of the plant sampling system that provide containment isolation are evaluated with the containment isolation system. Also, safety-related interface components (e.g., heat exchangers) are evaluated within the system that is used to remove heat. Another example in the post-accident sampling system is the Seismic Category I component cooling water and control tank purge line tie-ins. In part, 10 CFR 54.21(a)(1) states that components and their intended functions that meet the scoping criteria of 10 CFR 54.4(a) and are subject to an AMR must be identified and listed so that their aging effects can be adequately managed consistent with the CLB. In order to confirm that SSCs with intended functions described in the UFSAR using traditional (i.e., CLB) nomenclature have been captured in the license renewal process, the staff needs to identify components from out-of-scope systems that were evaluated as part of the in-scope systems in the information provided in the LRA and the license renewal boundary drawings. By letter dated March 21, 2003, as part of RAI 2.2-1, the staff requested that the applicant identify the components from out-of-scope systems (identified above) in the tables contained in LRA Section 2.3. The staff asked that the applicant identify the components of the plant sampling system that perform intended functions that are evaluated with the containment isolation and other systems, the intended functions they perform, and if they are subject to an AMR.

By letter dated June 10, 2003, the applicant responded that for plant sampling, the affected components are addressed in LRA Section 2.3.2.5, containment isolation components. The plant sampling system contains components that act as containment isolation boundaries (valves and pipe). Within the system evaluation boundary, no components, other than those that perform the isolation function, perform any additional license renewal intended functions. Therefore, this method of evaluation of the system components that perform the containment isolation boundary function within the containment isolation system results in the designation of plant sampling as not within the scope of license renewal. The components that are in scope and evaluated with the containment isolation system are shown between the SC-2 flags bounding the containment penetrations on drawings 33013-1278,1-LR and 33013-1279-LR. The affected components are pipe, valve bodies, delay coil, and flanges as listed in Table 2.3.2-5.

The staff reviewed the applicant’s response to RAI 2.2-1 regarding the evaluation of those portions of the plant sampling system that support the containment isolation function. The staff considers the applicant's response to be acceptable because the components of the plant sampling system that are subject to AMR have been adequately identified.

2.3.3.17.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's response to the staff's RAI to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified those portions of the plant sampling system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified those portions of the plant sampling system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.18 Plant Air

2.3.3.18.1 Summary of Technical Information in the Application

The plant air systems, although supplying valves in safety-related systems, are not designed as safety-related systems. Safety-related systems using instrument air are designed such that upon loss of air pressure, each component will fail in a position of greater safety. Components that require a pneumatic motive of force to achieve a safety function (e.g., pressurizer power-operated relief valves) have nitrogen backup that is evaluated with the system containing those components. Those portions of plant air that act as containment isolation devices are evaluated in the containment isolation system. Consequently, within the system evaluation boundary, there are no components that perform intended functions meeting the scoping requirements of 10 CFR 54.4(a), and the plant air system is not within the scope of license renewal.

The principal components of the plant air system are compressors, tanks, filters, dryers, and the essential piping and valves. The instrument air system supplies clean, dry air for valve operators and piping penetration pressurization. The service air system supplies air for maintenance and service use and the backup eductor for vapor extraction of the turbine generator bearing drains. A backup source of air supply to the instrument air header is from the service air system. The instrument air system produces 120 to 125 psig dry, filtered air used chiefly as the motive power for valve actuation. The system consists of three air compressors with an associated aftercooler and air reservoir for each compressor. Air from the receivers is supplied to the instrument air header through filters and an air dryer. The instrument air header delivers air to the various valve actuators, piping penetration pressurization system, and containment air and proof test system. The service air system produces 115 to 125 psig dry, filtered air used in the maintenance of air connections throughout the station for fire water storage tank pressurization and for the turbine lube-oil system. The system consists of one air compressor with an integral aftercooler and associated air receivers.

A cross-tie between service air and instrument air allows the service air system to supply the instrument air header if instrument air pressure drops below 90 psig. The cross-tie occurs prior to the instrument air filters. Therefore, air being supplied to the instrument air header will always pass through the filters and dryer. A cross-connect between the service air system and the instrument air system allows both systems to be supplied by a single rotary screw air compressor. A pressure regulator valve will stop air flow to the service air system if pressure on the service air side drops below 100 psig. As an administrative control, the instrument air system and service air system are cross-connected only when one of the rotary screw air compressors is in operation.

2.3.3.18.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.18 and UFSAR Sections 9.3.1 and 3.5.1.3.2.5 to determine whether there is reasonable assurance that the plant air system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of license renewal. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

The review confirmed the applicant's determination that the plant air systems, with the evaluation boundaries specified in the LRA and delineated in the accompanying scoping boundary drawings, do not perform an intended function that meets the scoping criteria of 10 CFR 54.4(a). The review also confirmed that the specific components of the plant air systems that the LRA identified as being evaluated with other systems were in fact included as components of other systems within the scope of license renewal.

On the basis of this review, the staff concludes that none of the components of the plant air systems, other than those evaluated within other systems, have intended functions that meet the requirements of 10 CFR 54.4(a). The staff considers the applicant's scoping and screening of the plant air systems to be in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

2.3.3.18.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's response to the staff's RAI to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately determined that none of the components of the plant air systems is within the scope of license renewal, as required by 10 CFR 54.4(a) or subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.19 Nonessential Ventilation

2.3.3.19.1 Summary of Technical Information in the Application

The nonessential ventilation system provides HVAC to nonvital areas and plant equipment. The nonessential ventilation system is not within the scope of license renewal as none of the components of these systems within the license renewal evaluation boundary perform intended functions that meet the criteria of
10 CFR 54.4(a).

The principal components of the nonessential ventilation system include filters, fans, dampers, valves, heat exchangers, conditioning/chiller packages, and the essential ductwork and piping and valves. Fire dampers contained in the system are evaluated as a separate commodity group.

The turbine building, while not requiring an HVAC system, uses roof vent fans, wall vent fans, windows, and unit heaters for ventilation and temperature control. The fans are not supplied by emergency power, and loss of these fans would not be critical to a safe shutdown. Included in the turbine building is the main feedwater pump room. Main feedwater pump equipment cooling systems use a mixture of outside air and room air to control the room and equipment temperatures. No mechanical means of heating or cooling is used. A temperature control system controls the feedwater pump room return air dampers and equipment outside air dampers that admit air to the equipment air supply fan plenum mixed at a setpoint temperature.

The service building ventilation system consists of air handling units serving the various areas of the service building. Air from uncontaminated areas is exhausted through roof exhaust fans. Air from areas of potential contamination, such as laboratories equipped with hoods, is exhausted through the controlled intermediate building controlled access area exhaust fans. Controlled access area fans 1A and 1B include HEPA and charcoal filter banks, a low-flow alarm, dampers, and fans. These fans take suction from the following areas and discharge to the auxiliary building HEPA filter vent, which is exhausted by the main auxiliary building exhaust system to the main vent header:

- men's and women's decontamination general areas
- radiation protection and chemistry office general area
- primary sample room general area
- primary sample hood
- primary and secondary sample lab hoods
- hot shop general area

The AVT building ventilation system provides ventilation and heating to maintain required temperatures for the AVT (condensate demineralizer) building and the condensate booster pump area of the turbine building.

The evaluation boundary for the nonessential ventilation system also includes baseboard circulating radiant heat in the service building and any HVAC equipment associated with nonsafety buildings not used in direct support of power production (e.g., engineering building, Butler building, records management (steam generator) building, etc.).

2.3.3.19.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.19 and UFSAR Sections 9.4.5 through 9.4.7 to determine whether there is reasonable assurance that the nonessential ventilation system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of license renewal. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted. As stated in the applicant's response to RAI 2.2-1 (discussed in Section 2.2 of this SER), fire dampers contained in the nonessential ventilation systems are evaluated as a separate commodity group.

The review confirmed the applicant's determination that the nonessential ventilation system, with the evaluation boundaries specified in the LRA and delineated in the accompanying scoping boundary drawings, does not perform an intended function that meets the scoping criteria of 10 CFR 54.4(a). The review also confirmed that the specific components of the nonessential ventilation system that the LRA identified as being evaluated with other systems were in fact included as components of other systems within the scope of license renewal.

On the basis of this review, the staff concludes that none of the components of the nonessential ventilation system, other than those evaluated with other systems, have intended functions that meet the requirements of 10 CFR 54.4(a). The staff considers the applicant's scoping and screening of the nonessential ventilation system to be in accordance with the requirements of 10 CFR 54.4(a), and 10 CFR 54.21(a)(1).

2.3.3.19.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's response to the staff's RAI to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately determined that none of the components of the nonessential ventilation system is within the scope of license renewal, as required by 10 CFR 54.4(a) or subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.20 Site Service and Facility Support

2.3.3.20.1 Summary of Technical Information in the Application

The site service and facility support systems evaluation boundary includes domestic (potable) water, domestic hot water, and the site sewage transfer to the municipal treatment system. This system is not within the scope of license renewal as components within the site service and facility support systems do not perform intended functions that meet the scoping criteria of 10 CFR 54.4(a). The principal components of the site service and facility support systems include heat exchangers, hot water heaters, pumps, and essential piping and valves. Domestic water is used for drinking, showers, eye wash stations, and various domestic applications. The sewage transfer system pumps collected sanitary discharges from the site to the municipal sanitary header offsite. The sewage transfer system does not interconnect with any potentially radioactive systems, so no radiation monitoring is required.

2.3.3.20.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.20 and UFSAR Sections 1.2.6 and 1.2.12 to determine whether there is reasonable assurance that the site service and facility support system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of license renewal. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

The review confirmed the applicant's determination that site service and facility support systems do not perform intended functions that meet the scoping criteria of 10 CFR 54.4(a). On the basis of this review, the staff concludes that the applicant's scoping and screening of the site service and facility support systems is in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

2.3.3.20.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's response to the staff's RAI to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified the components of the site service and facility support systems that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified the components of the site service and facility support systems that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.21 Evaluation Findings

On the basis of this review, the staff concludes that the applicant has adequately identified the auxiliary systems and components that are within the scope of license renewal, in accordance with the requirements of 10 CFR 54.4(a), and that the applicant has adequately identified the auxiliary systems and components that are subject to an AMR, in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.4 Steam and Power Conversion Systems

The steam and power conversion systems consist of the main and auxiliary steam, main feedwater and condensate, auxiliary feedwater, steam generator, turbine generator and support systems, and the associated components.

2.3.4.1 Main and Auxiliary Steam

2.3.4.1.1 Summary of Technical Information in the Application

The main and auxiliary steam system provides heat removal from the RCS during normal, accident, and post-accident conditions. During off-normal conditions, the system provides emergency heat removal from the RCS using secondary heat removal capability. Some nonsafety-related portions of piping in the system have failure modes which could prevent the satisfactory accomplishment of safety-related functions (HELBs). The system is also credited for safe shutdown following SBO and some fire events and contains components that are part of the Environmental Qualification Program. Selected safety valve discharge vent piping is considered nonsafety equipment whose failure could affect a safety function due to its importance in directing steam flow out of a safety-related area. The conversion of the heat produced in the reactor to electrical energy is evaluated in the discussion of the turbine generator system (Section 2.3.4.4).

The principal components of the main steam portion of the system include the secondary side of two steam generators, where the main steam lines begin. Each steam line has a flow restrictor, four main steam safety valves, an atmospheric dump valve, and a steam admission valve to the turbine-driven auxiliary feedwater (TDAFW) pump. The two steam lines join together in the intermediate building before entering the turbine building. Each steam line is also equipped with a fast-closing main steam isolation valve and a main steam nonreturn check valve. These valves prevent reverse flow in the steam lines which would result from an upstream steam line break, or they isolate any downstream steam line break at the common header. The atmospheric relief valves (ARVs) have two functions. They offer overpressure protection to the steam generator at a setpoint below the main steam safety valve setpoints and can be used to maintain no-load T_{AVG} or perform a plant cooldown in the event the steam dump to the condenser is not available.

The principal components of the auxiliary steam portion of the system include the piping valves and tanks in the extraction steam and steam generator blowdown subsystems. In extraction steam, five stages of extraction are provided—two from the high-pressure turbine, one of which is the exhaust, and three stages from the low-pressure turbines. There are also two steam dump lines with four relief valves each to the condenser.

Continuous steam generator blowdown is used to reduce the quantities of solids that accumulate in the steam generators as a result of the boiling process. The blowdown recovery system is designed to recover both the blowdown water and heat. Each steam generator has a blowdown header located at the bottom of the shell side just above the tubesheet. Both steam generators are equipped with independent blowdown piping from the connecting steam generator nozzles to a flash tank. The piping transports the removed fluid and entrapped debris away from the steam generator, through containment penetrations, to a common flash tank in the turbine building basement. Flashed steam is vented from the flash tank to low-pressure feedwater heater 3A for heat recovery. The vented steam condenses in the feedwater heater and returns to the condenser through the feedwater heater drain system. The remaining condensate in the blowdown flash tank is drained directly to condenser 1B through a level control valve.

2.3.4.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.1 and UFSAR Sections 5.4.6, 10.1.1, 10.3, and 10.7 to determine whether there is reasonable assurance that the main and auxiliary steam system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of license renewal. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

During its review of LRA Section 2.3.4.1, the staff determined that additional information regarding the safe shutdown motive force (i.e., nitrogen bottles) for the atmospheric dump valves, also referred to as ARVs, was needed to complete its review. Section 10.3.2.5 of the Ginna UFSAR states that “backup supply (to the ARVs) is provided by two non-seismic nitrogen supply systems in the event that a loss of offsite power causes loss of the instrument air system.” License renewal boundary drawing 33013-1231-LR identifies the nitrogen bottles, and associated tubing, piping, and valves as subject to an AMR. However, Table 2.3.4-1 of the LRA does not list the nitrogen bottles of interest as requiring an AMR. Since the UFSAR identifies the nitrogen bottles as a power supply for the atmospheric dump valves, and the dump valves are required for safe shutdown, the staff believes the nitrogen supply is within the scope of license renewal per 10 CFR 54.4(a) and is subject to an AMR per 10 CFR 54.21(a)(1). By letter dated March 21, 2003, the staff requested that the applicant explain the apparent omission of nitrogen bottles from being subject to an AMR (RAI 2.3.4.1.-1). If the nitrogen bottles are considered to be consumable, the staff requested a description of the replacement program.

In a letter dated May 13, 2003, the applicant responded that the nitrogen bottles are in the scope of license renewal with no AMP required since they are a commodity item, replaced on condition. A daily operation log check, per Ginna procedure O-6.11 is performed, and if the pressure is found to be less than 1000 psi, the bottle is changed. The staff finds the applicant's response to be acceptable on the basis that the nitrogen bottles are a consumable item that are replaced according to specified criteria, as documented in the letter from Stephen S. Koenick, NRC, to the NEI entitled, "Summary of the December 8, 1999 Meeting on License Renewal Issue (LR) 98-12, 'Consumables,'" January 12, 2000.

During the review of the license renewal boundary drawings associated with the main steam system, the staff determined that additional information was needed regarding ending the licensing renewal boundary at normally open valves (see license renewal boundary drawing 33013-1232-LR at locations E7 and F7 and 33013-1277,1-LR, at locations C5 and H5). In the LRA on page 2-19, the applicant states the following:

> The LR evaluation markups for a system have typically been extended to the first normally closed manual valve, check valve or automatic valve that gets a signal to go closed. A normally open manual valve has also been used as a boundary in a few instances where a failure downstream of the valve has no short term effects, can be quickly detected, and the valve can be easily closed by operators to establish the pressure boundary prior to any adverse consequences. However, for station blackout (SBO), Appendix R, high-energy line break (HELB), and flooding events, the license renewal boundaries for a system have been defined consistent with the boundaries established in the CLB evaluations. Those boundaries do not always coincide with an isolation device.

By letter dated March 21, 2003, the staff requested that the applicant provide a brief discussion of the steps for closing the valves during events such as HELBs, SBO, and fires, the amount of time required to complete these steps, and any other pertinent information to justify an open boundary at these valves (RAI 2.3.4.1-2). Similarly, the staff requested justification for the exclusion of several branch lines depicted on license renewal drawing 33013-1232-LR (see locations B6 and E6) from being subject to an AMR (RAI 2.3.4.1-3). Failure of these branch lines may affect the pressure boundary intended function of the main steam line.

In a letter dated May 13, 2003, the applicant responded that an explanation is included in Note 3 of the drawing which states, "In accordance with EWR 5114, 30" and 24" main steam lines up to and including valves 3544 and 3545 as well as the 12" lines up to and including valves 3532 and 3533 are safety significant class for high-energy consideration only. Class boundary for all branch lines is at the connection to the main piping." The Ginna Station is designed to withstand the effects of HELB on all other piping segments, and therefore no isolation is required. The applicant pointed out that the NRC reviewed and accepted the analyses and facility design modifications for HELBs outside containment, and that acceptance is documented in a letter dated August 24, 1979, to L.D. White, Jr., RG&E, subject: Amendment No. 29 to License No. DPR-18. With regard to RAI 2.3.4.1-3, the applicant referred to the NRC letter dated August 24, 1979. The applicant further stated that the HELBs were subsequently identified on the main steam and feedwater system P&IDs through EWR 5114. The staff finds the applicant's response to be acceptable on the basis that the applicant's position is consistent with the CLB of the Ginna plant.

During the review of license renewal drawing 33013-1231-LR, the staff identified flanged flexible hose connections that are shown to be subject to an AMR (see locations C7 and I7). However, Table 2.3.4-1 of the LRA does not contain an entry for this component type. By letter dated March 21, 2003, the staff requested that the applicant clarify if flanged flexible hose connections are considered to be part of the component group “pipe” or some other component type listed in Table 2.3.4-1, and if not, justify the exclusion of these components from the scope of license renewal (RAI 2.3.4.1-4).

In a letter dated May 13, 2003, the applicant responded that the flanged flexible hose connections are considered as part of the component group “pipe.” The staff finds the applicant’s response to be acceptable on the basis that it clarifies that the flanged flexible hose connections are subject to an AMR.

During the review of license renewal drawing 33013-1231-LR, the staff identified at location E8 a screwed cap that is shown as being subject to an AMR because it serves as a pressure boundary intended function. However, a similar screwed cap at location I8 is not shown as being subject to an AMR. By letter dated March 21, 2003, the staff requested that the applicant clarify if this is a drafting error or if this segment of piping was intentionally shown as not subject to an AMR (RAI 2.3.4.1-5).

In a letter dated May 13, 2003, the applicant responded that this is a typographical error. The screwed cap at location I8 is in scope and is subject to an AMR. The staff finds the applicant’s response to be acceptable as it explains that the component was omitted because of a typographical error and clarifies that the screw cap is subject to an AMR.

During the review of Table 2.3.4-1 of the LRA, the staff identified “operator” as a component group that requires an AMR. However, the referenced drawings for the main and auxiliary steam systems do not show any valve operators as requiring an AMR. By letter dated March 21, 2003, the staff requested that the applicant clarify whether the operator listed in Table 2.3.4-1 is associated with the atmospheric dump or relief valve (valves 3410 and 3411) (RAI 2.3.4.1-6).

In a letter dated May 13, 2003, the applicant confirmed that the operator listed in Table 2.3.4-1 is associated with the atmospheric dump and relief valves 3410 and 3411. Furthermore, the applicant stated that the operators should be shown as requiring AMR on drawing 33013-1231-LR for these two valves. Thus, this is a typographical error. The staff finds the applicant’s response to be acceptable as it explains that the operators were omitted because of a typographical error and clarifies that the operators are subject to an AMR.

2.3.4.1.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant’s responses to the staff’s RAIs to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified the components of the main and auxiliary steam systems that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified the components of the main and auxiliary steam systems that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.2 Feedwater and Condensate

2.3.4.2.1 Summary of Technical Information in the Application

The feedwater and condensate systems function to condense the steam exhausted from the low-pressure turbines, collect and store this condensate, and then send it back to the steam generator for reuse. Components within the system are used to provide emergency heat removal from the RCS using secondary heat removal capability. The ESF actuation system provides actuation signals for feedwater isolation. Portions of the main feedwater piping systems in the intermediate building and the turbine building have failure modes and effects which could prevent the satisfactory accomplishment of a safety-related function HELB. The feedwater lines are equipped with a nonreturn check valve and an isolation valve in each line. The nonreturn valve is the boundary between Seismic Category I and nonseismic feedwater piping and prevents the steam generator from blowing back through the feedwater lines if damage occurs to the nonseismic portion. Components within the feedwater and condensate system are also credited for use in safe shutdown following SBO events and some fires. Additionally, components within the system perform functions used to mitigate ATWS and components that are part of the Environmental Qualification Program.

The principal components of the feedwater and condensate system are the feedwater and condensate pumps, the feedwater regulating and bypass valves, the feedwater heaters, and the essential piping and valves. The steam that leaves the exhaust of the low-pressure turbines enters the main condenser as saturated steam with low moisture content. This steam is condensed by the circulating water, which passes through the tubes of the condenser. The condensed steam collects in the condenser hotwell from which the condensate pumps take suction. The condensate pumps increase the pressure of the water and provide suction head for the condensate booster pumps. The condensate booster pumps, in turn, provide sufficient suction head for the main feedwater pumps. Between the condensate pumps and the condensate booster pumps is the condensate demineralizer system, which maintains condensate water purity. The condensate booster pumps flow condensate through the condensate cooler, hydrogen coolers, air ejector condensers, gland steam condenser, and low-pressure heaters to the suction of the feedwater pumps. The feedwater pumps send feedwater through the high-pressure heaters to the steam generators via the feedwater regulating valves.

2.3.4.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.2 and UFSAR Sections 5.4.6, 10.1.1, and 10.4 to determine whether there is reasonable assurance that the feedwater and condensate system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of license renewal. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

During the review of license renewal boundary drawing 33013-1236, 2-LR, the staff determined that additional information regarding flow transmitters was needed to complete its review. One flow transmitter is shown as being subject to an AMR, but others on the drawing are not. Note 5 on the drawing indicates that these flow transmitters are considered “safety significant” class for pressure boundary considerations. Note 1 to Table 2.3.4-2 of the LRA indicates that selected instruments were conservatively included in the scope of license renewal if the instrument is unisolable from a pressure source and is of sufficient size that a system function would be degraded should the pressure boundary fail. Although the transmitters in question appear to be isolable, the instrument line size is not indicated. By letter dated March 21, 2003, the staff requested that the applicant briefly discuss the justification for these specific transmitters not being subject to an AMR (RAI 2.3.4.2-1).

In a letter dated May 13, 2003, the applicant responded that flow transmitter FT 466 at location B4 is shown to be subject to an AMR due to a typographical error; therefore, FT 466 is not within the scope of license renewal. Flow transmitters are considered active devices and do not require an AMR. The staff finds the applicant’s response to be acceptable because it acknowledges that the flow transmitter in question was incorrectly identified as subject to an AMR due to a typographical error.

During the review of LRA Section 2.3.4.2 and Ginna UFSAR Section 15.1.1.1, the staff determined that additional information regarding the main feedwater regulating valve was needed to complete its review. By letter dated March 21, 2003, the staff asked the applicant to clarify why the operator to the main feedwater regulating valve is not subject to AMR, while other operators are included in the scope of license renewal and subject to an AMR (RAI 2.3.4.2-2). The operator in question is credited for isolation in the CLB analysis presented in Section 15.1.1.1 of the UFSAR.

In a letter dated May 13, 2003, the applicant responded that the operators to the main feedwater regulating valves are not subject to AMR because those valves fail to the safe position (closed) on loss of operator pressure boundary, thus providing the feed regulating valve isolation function. The steam generator atmospheric relief valves and pressurizer PORVs must operate both open and closed to satisfy their safety functions; thus, the operators and their associated pressure boundaries provide a license renewal intended function and require an AMR. The staff finds the applicant’s response to be acceptable as the operators do not perform an intended function per the scoping criteria of 10 CFR 54.4(a).

2.3.4.2.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant’s responses to the staff’s RAIs to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified the components of the feedwater and condensate systems that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified the components of the feedwater and condensate systems that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.3 Auxiliary Feedwater

2.3.4.3.1 Summary of Technical Information in the Application

The AFW system is designed to maintain the steam generator water inventory when the normal feedwater system is not available. During accident and post-accident conditions, the AFW system supplies feedwater to the steam generators in order to provide emergency heat removal from the RCS using secondary heat removal capability (atmosphere or main condenser). The AFW system is also credited for use in mitigating ATWS and safe shutdown following SBOs and some fires.

The principal components of the AFW system are electric-motor-driven and steam-turbine-driven pumps, the turbine-driven feedwater pump (TDAFW) oil system, and the essential piping and valves. The preferred AFW system is divided into two independent trains. Two motor-driven pumps are powered from separate redundant 480-V safeguard emergency buses which can receive power from either onsite or offsite sources. Each motor-driven pump can provide 100 percent of the preferred AFW system flow required for decay heat removal and can be cross-connected to provide flow to either steam generator. There is also a turbine-driven pump which can receive motive steam from each steam line and provide flow to either or both steam generators. The turbine-driven pump provides 200 percent of the flow required for decay heat removal.

An SAFW system provides flow in case the preferred AFW system pumps are inoperable (e.g., an HELB event could render inoperable the three preferred AFW pumps). The SAFW uses two motor-driven pumps which can be aligned to separate SW system loops. The SAFW has the same features as the preferred AFW system pumps with regard to functional capability and power supply separation. The system is manually actuated from the control room.

The condensate storage tanks (CSTs) are the normal (preferred) suction source for delivery of cooling water to the steam generators. The safety-related supply is from the plant service water system with the fire water system as a backup source.

2.3.4.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.3, UFSAR Sections 7.2.6, 10.5, and 10.7.4, and Table 6.2-15a to determine whether there is reasonable assurance that the AFW system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of license renewal. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

During the review of license renewal boundary drawing 33013-1234-LR, the staff determined that additional information was needed regarding the CSTs. The manways on CSTs "A" and "B" are shown to be subject to an AMR; however, they are not listed in Table 2.3.4-3. A 6-inch vent on the top of CSTs "A" and "B" is not shown to be subject to an AMR. By letter dated March 21, 2003, the staff asked the applicant to explain why manways are not included in the subject table and why the vent is not subject to an AMR, or to indicate whether there is an alternate means to provide vacuum protection for this tank (RAIs 2.3.4.3-1 and 2.3.4.3-2).

In a letter dated May 13, 2003, the applicant responded that the manways on CSTs "A" and "B," which are shown in scope on drawing 33013-1234-LR, are evaluated as part of the tank. The applicant further stated that all manways were evaluated as part of the associated tank with the exception of the pressurizer where the manway construction is unique (bolted loose liner versus integral or weld overlay clad on vessel interior). With regard to the 6-inch vent, the applicant stated that there is no credible aging effect that would cause a large vent to fail in a manner which would create a tight seal on top of these tanks. Therefore the 6-inch vents were not included within the scope of license renewal. The staff finds the applicant's responses to be acceptable as the manways were evaluated as part of their associated tank and no credible aging effect could cause the 6-inch vents to fail in a way that would affect tank operation.

During the review of license renewal boundary drawing 33013-1234-LR, the staff determined that additional information was needed regarding ending the license renewal boundary for AMR at a normally open valve (valve 4047 at location I5). The staff noted that a piping class change occurs at this valve. The note on page 2-19 of the LRA indicates that normally open manual valves are used as a boundary if failure of the downstream piping has no short-term effects, can be quickly detected, and can be easily closed by the operators to establish the pressure boundary before any adverse consequences occur. The staff was unable to determine which of these cases apply for this particular valve. By letter dated March 21, 2003, the staff requested that the applicant explain why it is acceptable to terminate the license renewal boundary at this normally open valve (RAI 2.3.4.3-3).

In a letter dated May 13, 2003, the applicant responded by referring to Section 2.1.7.1 of the LRA, which states for SBO, Appendix R, HELB, and flooding events, the license renewal boundaries for a system have been defined consistent with the boundaries established in the CLB evaluations. Those boundaries do not always coincide with a closed isolation device. Valve 4047 is used to establish an SBO boundary that envelops the CSTs. Should the need arise, operating procedures reconfigure the valve to closed and establish a boundary so that the tanks can be refilled from various sources (in scope of license renewal). In this manner, a steady supply source or the turbine-driven AFW pump is maintained for the required SBO coping duration. The staff finds the applicant's response to be acceptable on the basis that sufficient time and approved procedures exist to close the valves in question if necessary.

During review of license renewal boundary drawing 33013-1237-LR, the staff determined that additional information regarding flow elements was needed to complete its review. Flow elements at locations F9, I7, and J8 are shown to be subject to an AMR; however, flow element FE 2006 at location I10 is not. By letter dated March 21, 2003, the staff requested that the applicant clarify if this is a typographical error, or justify its exclusion from an AMR (RAI 2.3.4.3-4).

In a letter dated May 13, 2003, the applicant responded that this is a typographical error. Flow element FE 2006 at location I10 is in the scope of license renewal and should have been shown on the drawing as requiring an AMR. The staff finds the applicant's response to be acceptable, as it acknowledges that flow elements are subject to an AMR.

During a review of Table 2.3.4-3 of the LRA, the staff determined that additional information regarding the component group "governor" was needed to complete its review. In the table, a "governor" is indicated to be subject to an AMR. After review of the various documents and drawings, the staff was unable to identify which "governor" or "governors" are intended to be subject to an AMR. By letter dated March 21, 2003, the staff asked the applicant to clarify which valve governor or governors are intended by the component group listed in Table 2.3.4-3 (RAI 2.3.4.3-5).

In its response dated May 13, 2003, the applicant stated that the governor for valve 9519E should have been shown as requiring an AMR on drawing 33013-1231-LR, since it is within the scope of license renewal. This is a typographical error. The governor for valve 9519E is the only component applicable to the group governor listed in Table 2.3.4-3. The staff finds the applicant's response to be acceptable on the basis that the valve governor in question was omitted due to a typographical error but is now acknowledged to be subject to an AMR.

During review of relevant portions of the Ginna UFSAR, the staff determined that additional information regarding yard fire hydrant connections was needed to complete its review. Section 10.5.3.1.4 of the Ginna UFSAR states that connections have been provided allowing the use of the yard fire hydrant system to fill the CSTs as a source of water for the motor-driven and turbine-driven pumps. The staff could not identify these connections on the license renewal boundary drawings. Based on the statement in the UFSAR, it appears that the hydrant connections should be within the scope of license renewal and subject to an AMR. By letter dated March 21, 2003, the staff requested that the applicant explain why such connections do not require an AMR (RAI 2.3.4.3-6).

In a letter dated May 13, 2003, the applicant responded that this is a typographical error. The use of the yard fire hydrant system to fill the CSTs is documented in Ginna Emergency Response Procedure ER-AFW.1. This procedure specifies running the fire hose from hose reel #2 and connecting at valve 4049C. Hose reel #2 (shown on drawing 33013-1990, 2), along with the yard fire hydrant system piping, is included in the scope of license renewal and is shown within the drawings listed for the fire protection system in LRA Section 2.3.3.6. The fire system piping connection shown on drawing 33013-1234, at location H7, is shown incorrectly as black, and is a typographical error. The staff finds the applicant's response to be acceptable on the basis that the connections were omitted due to a typographical error but are now acknowledged to be subject to an AMR.

2.3.4.3.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's responses to the staff's RAIs to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified the components of the auxiliary feedwater system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified the components of the auxiliary feedwater system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.4 Turbine Generator and Supporting Systems

2.3.4.4.1 Summary of Technical Information in the Application

The turbine generator and supporting systems function to convert the energy of the heat contained in the main steam into mechanical energy for use in turning the electric generator. These systems have no safety-related functions. Turbine first-stage pressure instruments provide a signal used in ATWS mitigating system actuation circuitry (AMSAC).

The plant subsystems with a boundary of the turbine generator and supporting systems include the high- and low-pressure turbine generator and controls, the main electrical generator, the electro-hydraulic control system, the turbine lube oil system, condenser air ejector and vacuum priming, generator hydrogen cooling, and generator seal oil systems.

The principal components of the turbine generator systems include turbines, the main generator, pumps, tanks, heat exchanges, and the essential piping and valves. The main turbine is made up of one high-pressure and two low-pressure turbines, all mounted on a common shaft. The steam flowpath is first through the high-pressure turbine, then in a parallel path to the two low-pressure units via the four moisture separator reheaters. High-pressure steam is admitted to the high-pressure turbine through two stop and four governing control valves. These valves are controlled by the electro-hydraulic control system. Turbine supervisory instrumentation is provided to monitor turbine vibration, eccentricity, and differential thermal expansion and provide alarms in the control room in the case of abnormal conditions.

The main turbine is supported by a number of auxiliary systems that improve the efficiency and safety of its operation. First- and second-stage air ejectors remove air and noncondensible gases from the condenser and maintain it under a vacuum, improving the efficiency of the main turbine by reducing the backpressure seen by the turbine exhaust. The gland sealing and exhaust system applies steam to a labyrinth seal around the rotor shaft to preclude air in-leakage into the turbine casings and condenser and to prevent steam leakage into the turbine building. The vacuum priming system uses mechanical vacuum pumps to prevent air buildup in the condenser water boxes or tubes, a condition that would reduce condenser efficiency. The exhaust hood spray prevents overheating of the last-stage, low-pressure blading under low-steam flow conditions. The turbine lube oil system provides lubrication and cooling of the turbine bearings and supplies oil to the auto-stop header for turbine protection. It also provides backup oil to the seal oil system to prevent hydrogen leakage into the turbine building. A purification system is an adjunct to the turbine lube oil system to remove water and contaminants from the lube oil, as well as to provide storage space for makeup oil. The generator auxiliary systems are required to ensure that the main generator will operate safely and efficiently at its maximum rated output. This is accomplished by cooling the generator rotor, stator, exciter, main output bushings, and the isophase bus ducts. Pressurized hydrogen is circulated by the internal ventilation of the generator to remove heat produced in the rotor and stator. The hydrogen then transfers this heat to hydrogen coolers which are supplied with cooling water from the condensate system. To prevent the escape of hydrogen along the generator shaft and out of the casing, a seal oil system is utilized. The air-side seal oil pump and the hydrogen-side seal oil pump provide oil for sealing at pressure higher than generator hydrogen pressure. The main turbine oil system can provide a backup source of pressurized seal oil.

2.3.4.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.4 and UFSAR Sections 7.2.6 and 10.2 to determine whether there is reasonable assurance that the turbine generator and supporting system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1). In the performance of its review, the staff selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of license renewal. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

During its review of Section 2.3.4.4 and the Ginna UFSAR, the staff determined that additional information regarding the turbine stop valves was needed to complete its review. Section 7.2.6 of the Ginna UFSAR states that the AMSAC is a non-Class 1E system designed to trip the turbine and start the AFW pumps if main feedwater flow is lost with reactor power above 40 percent. The valves and piping associated with the pressure transmitters have been included in the scope of license renewal and are listed in LRA Table 2.3.4-4 as being subject to an AMR. Section 2.3.4.4 of the LRA states that pressure sensors for the turbine first-stage pressure provide a signal used in the AMSAC. The turbine stop valves are also identified as being subject to an AMR on license renewal boundary drawing 33013-1232 at locations B6 and E6. However, the LRA system function listing for code Z4 does not cite the turbine stop valves as having an ATWS intended function. Intended functions should be identified in accordance with the requirements of 10 CFR 54.4(a)(3). By letter dated March 21, 2003, the staff requested that the applicant clarify the intended function of the turbine stop valves that led to their inclusion in the scope of license renewal and to their being subject to an AMR (RAI 2.3.4.4-1).

In a letter dated May 23, 2003, the applicant responded that, in accordance with 10 CFR 50.62, the scope of ATWS includes “equipment from the sensor output to final actuation device...to...initiate a turbine trip. . .” For the Ginna Station, that equipment includes the turbine first-stage pressure sensors (sensor output) to the turbine auto stop trip solenoids (final actuation device). The turbine stop valves are in the scope of license renewal according to 10 CFR 54.4(a)(2), in that they are the boundary valves for high-energy piping, the failure of which could cause damage to safety-related equipment in the intermediate building, which is adjacent to the turbine building in which the turbine stop valves are located. The staff finds the applicant’s response to be acceptable on the basis that the turbine stop valves are within the scope of license renewal because they are boundary valves.

2.3.4.4.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant’s response to the staff’s RAI to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified the components of the turbine generator and supporting systems that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified the components of the turbine generator and supporting systems that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.5 Evaluation Findings

On the basis of this review, the staff concludes that there is reasonable assurance that the applicant has appropriately identified the steam and power conversion systems and components that are within the scope of license renewal, in accordance with the requirements of 10 CFR 54.4(a), and that the applicant has appropriately identified the steam and power conversion system components that are subject to an AMR, in accordance with the requirements of 10 CFR 54.21(a)(1).

2.4 Scoping and Screening Results: Structures

This section addresses the scoping and screening results of structures for license renewal. The structures consist of the following:

- containment structures (2.4.1)
- auxiliary building (2.4.2.1)
- intermediate building (2.4.2.2)
- turbine building (2.4.2.3)
- diesel building (2.4.2.4)
- control building (2.4.2.5)
- all-volatile water treatment building (2.4.2.6)
- screenhouse building (2.4.2.7)

- standby auxiliary feedwater building (2.4.2.8)
- service building (2.4.2.9)
- cable tunnel (2.4.2.10)
- essential yard structures (2.4.2.11)
- component supports commodity group (2.4.2.12)
- nonessential buildings and yard structures (2.4.3)

Per 10 CFR 54.21(a)(1), an applicant must identify and list SCs subject to an AMR. These are passive, long-lived SCs that are within the scope of license renewal. To verify that the applicant has properly implemented its methodology, the staff focuses its review on the implementation results. Such a focus allows the staff to confirm that there is no omission of structural components that are subject to an AMR. If the review identifies no omission, the staff has the basis to find that there is reasonable assurance that the applicant has identified the structural components that are subject to an AMR.

2.4.1 Containment Structures

2.4.1.1 Summary of Technical Information in the Application

The applicant described the containment structure in LRA Section 2.4.1 and provided a list of components subject to an AMR in LRA Table 2.4.1-1.

The reactor containment structure is a reinforced concrete, vertical right cylinder with a flat base and a hemispherical dome. The structure houses and supports safety-related equipment, provides radiation shielding, and provides a barrier against the release of radioactive nuclides. A welded steel liner is attached to the inside face of the concrete shell to ensure a high degree of leak tightness. The thickness of the liner in the cylinder and dome is 3/8 inch and in the base is 1/4 inch. The cylindrical reinforced concrete walls are 3 feet 6 inches thick, and the concrete hemispherical dome is 2 feet 6 inches thick. The concrete base slab is 2 feet thick with an additional 2-feet-thick concrete fill over the liner plate. The containment structure is 99 feet high to the spring line of the dome and has an inside diameter of 105 feet. The containment vessel provides a minimum free volume of approximately 972,000 cubic feet.

Access to the containment structure is provided by means of two airlocks designed with an interlocked single-door-opening feature that is leak testable at containment design pressure between doors. One airlock is removable so that large equipment can be moved into and out of containment. The major components of the RCS are located within the containment structure. The containment structure provides a physical barrier to protect the equipment from natural disasters and shielding to protect personnel from radiation emitted from the reactor core while at power. Thick reinforced concrete walls are located around selected RCS components to serve as shielding for plant personnel. These walls also serve as a missile barrier to prevent damage to the containment wall and to components of the SI system should a failure occur in one of the RCS components located inside the walls.

The containment structure also provides housing and interfaces with equipment and component supports. Major component supports include the reactor vessel, SGs, RCPs, and the pressurizer. The component supports are attached either to the concrete foundation, concrete floor slabs, or shield walls through steel embedments or structural steel members encased in concrete. The containment structure consists of a reinforced concrete cylinder post-tensioned in the vertical direction and reinforced circumferentially with mild steel deformed bars. The dome is hemispherical and constructed of reinforced concrete. The base slab and ring beam support the dome and cylinder walls. The ring beam rests directly on rock and is the location of the end anchorage for the rock anchors. No drainage or de-watering system is provided under the containment structure. The base of the cylinder is supported by a neoprene pad, which provides a hinge support at the base. The vertical post-tensioning system is anchored at the base of the cylinder to rock anchors. The rock anchors are post-tensioned and grouted, which ensures that the rock acts as an integral part of the containment.

A Tendon Surveillance Program, in accordance with RG 1.35, Revision 2, is required by the station technical specifications. Provision is made to periodically monitor leakage by pressurizing the penetrations and containment. The containment structure and all penetrations are designed to withstand, within design limits, the combined loadings of the design-basis accident and design seismic conditions. All piping systems that penetrate the containment are anchored in the penetration sleeve or the structural concrete of the containment structure. The penetrations for the main steam, feedwater, blowdown, and sample lines are designed so that the penetration is stronger than the piping system and the containment will not be breached due to a postulated pipe rupture. For mechanical penetrations that interface with hot fluid systems, a containment penetration cooling system is used to prevent the bulk concrete temperature surrounding the penetrations from exceeding 150 °F. Containment electrical penetrations are designed so the containment structure can, without exceeding the design leakage rate, accommodate the postulated environment resulting from a LOCA. The electrical penetrations have been shown to maintain structural integrity when subjected to mechanical stresses caused by large magnitude fault currents.

A fuel transfer penetration is provided for fuel movement between the refueling transfer canal in the reactor containment and the SFP. The penetration consists of a stainless steel pipe installed inside a larger pipe. The inner pipe acts as the transfer tube and connects the refueling canal with the SFP. The tube is fitted with a standard stainless steel flange in the refueling canal and a stainless steel sluice gate valve in the SFP. The outer pipe is welded to the containment liner. The fuel transfer penetration, like all other penetrations, is anchored in the containment shell. Because this anchor point moves when the containment vessel is subjected to load, expansion joints are provided where the penetration is connected to structures inside and outside of the containment vessel. The expansion bellows inside the containment vessel provide a water seal for the refueling canal and accommodate thermal growth of the penetration from the anchor, as well as the pressure and earthquake produced motion of the anchor (the containment shell). The expansion joint accommodates motion of the sleeve within the containment shell relative to the portion of the sleeve anchored in the wall of the refueling canal in the auxiliary building.

The containment structure contains racks, panels, electrical enclosures, and equipment supports. Additionally the structure contains radiant heat shields and an RCP oil collection system credited with preserving the ability to achieve safe shutdown in the event of a fire in the containment. These equipment sets receive a separate commodity group evaluation independent of the structure evaluation. Refueling equipment and the cranes located in the containment also are evaluated separately.

Table 2.4.1-1 of the LRA lists 23 structural component groups requiring an AMR, provides a reference to the results of the AMR for each component group, and identifies the following intended functions for these structural component groups:

- structural/functional support for nonsafety-related equipment
- structural support for safety-related equipment
- pressure boundary/leak barrier
- radiation/heat shielding
- pipe-whip restraint
- shelter/protection of equipment
- pressure boundary

2.4.1.2 Staff Evaluation

The staff reviewed LRA Section 2.4.1 and UFSAR Sections 3.8.1, 3.8.2, and 3.8.3 to determine whether there is reasonable assurance that the containment structural components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In its performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Table 2.4.1-1 of the LRA lists the following 23 component groups that require an AMR:

(1) CV-BLOCK-INT (masonry block walls and mortar)

(2) CV-C-BUR (concrete in the containment vessel that is in contact with the soil and ground water; and embedded steel, reinforcement, and the embedded portion of anchor bolts and sealing materials used below grade in the containment vessel)

(3) CV-C-EXT (concrete in the containment vessel that is exposed to the weather; embedded steel, reinforcement, and the embedded portion of anchor bolts; and containment tendon conduit, expansion bellows, etc., encased in concrete)

(4) CV-C-INT (concrete in the containment vessel that is protected from the weather including the biological shield walls and missile barriers; embedded steel, reinforcement, and the embedded portion of anchor bolts; grout, used under column base plates)

(5) CV-ELAST-EXT (elastomer materials used in the containment vessel that are exposed to the weather and neoprene gaskets used to seal the tendon grease cans)

(6) CV-ELAST-INT(elastomer materials used in the containment vessel that are protected from the weather; and caulking used between thermal insulation panels and between the containment floor and the insulation)

(7) CV-EPOX-INT (epoxy in the containment vessel that is protected from the weather, and epoxy resin used to encapsulate the exposed tendon fill port piping)

(8) CV-FAST(CS)-INT (the exposed portion of carbon steel threaded fasteners for the containment vessel that are protected from the weather)

(9) CV-INSULATION (the containment vessel thermal insulation panels)

(10) electrical penetrations (pressure retaining boundary of the electrical penetration, including any sleeves or dissimilar metal welds)

(11) CV-SS(CS)-EXT (carbon structural steel in the containment vessel that is exposed to the weather, such as containment tendon grease cans)

(12) CV-SS(CS)-INT (carbon structural steel in the containment vessel that is protected from the weather; columns, posts, beams, baseplates, bracing, crane support girders, crane rails, and the exposed faces of plates and structural members, but not including carbon structural steel used as component supports)

(13) CV-SS(CS)-LINER (carbon steel of the containment vessel liner that is protected from the weather)

(14) CV-SS(CS)-ROCK ANCHOR (high-strength carbon steel rock anchors grouted into bedrock, including the button head of the bottom anchor)

(15) CV-SS(CS)-TENDONFILL (carbon steel grease fill ports)

(16) CV-SS(CS)-TENDONS (high-strength carbon steel tensioning tendon wire cluster encapsulated in NO-OX-ID (paraffin/mineral oil wax) and the top rock anchor button head)

(17) CV-SS(SS)-INT (stainless structural steel of the containment vessel that is protected from the weather, the refueling cavity, and fuel transfer liners, including attachments)

(18) mechanical penetrations (pressure retaining boundary of the mechanical penetration, including any penetration sleeves, bellows, and dissimilar metal welds)

(19) SPP01 (the movable hatch and mechanical wear surfaces of the personnel hatch)

(20) SPP01-GASKET (the inner and outer elastomeric seals for the hatch doors)

(21) SPP02 (The movable hatch and mechanical wear surfaces of the equipment hatch)

(22) SPP02-GASKET (the inner and outer elastomeric seals for the hatch doors as well as the containment vessel to hatch seal)

(23) VALVE BODY (the bronze manual valves attached to the tendon fill port piping)

The LRA states that the initial step in scoping is defining the entire plant in terms of major systems and structures. All of these systems and structures are evaluated against the scoping criteria in 10 CFR 54.4(a)(1), (2), and (3), to determine if they perform, support, or could adversely impact a critical safety function for responding to a design-basis accident event, or perform or support a specific requirement of one of five regulated events (fire protection, environmental qualification, pressurized thermal shock, and anticipated transients without scram). This step is accomplished using the UFSAR, technical specifications, licensing correspondence files, DBDs, controlled drawings, the Q-list, and the CMIS, a controlled data base which stores equipment and licensing basis information. During the scoping process, even if only a portion of a system or structure meets the scoping criteria of 10 CFR 54.4, the system or structure is identified as in the scope of license renewal for subsequent screening. The screening process defines the intended functions, such as pressure boundary, for structures and structural components for license renewal purpose. The screening process identifies those structures and structural components that meet the requirements contained in 10 CFR 54.21 as requiring an AMR. The LRA states that, to optimize the AMR, structures that are attached to or contained within larger structures have been reviewed with the larger structure, and that structural elements that have similar materials and experience similar environments have been grouped and reviewed together. The staff has reviewed the information in LRA Section 2.4.2.1 and the UFSAR. The staff finds that the applicant made no omissions in scoping and screening the containment structures for license renewal.

2.4.1.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant’s responses to the staff’s RAIs to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified the structural components of the containment that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified the structural components of the containment that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2 Essential Buildings and Yard Structures

2.4.2.1 Auxiliary Building

2.4.2.1.1 Summary of Technical Information in the Application

The applicant described the auxiliary building in LRA Section 2.4.2.1 and provided a list of components subject to an AMR in LRA Table 2.4.2-1.

The auxiliary building is a Seismic Category I three-story rectangular structure measuring approximately 70 feet by 214 feet. It is located south of the containment and intermediate buildings and adjacent to the service building. The auxiliary building houses the major support and ESF equipment required for plant operation. Portions of the structure act as fire barriers. The building contains nonsafety elements whose failure can affect a safety function (portions of the structure are designed to resist, and protect equipment from, HELBs, flooding, and tornadoes). The auxiliary building is part of a complex of interconnected buildings surrounding, but structurally independent of, the containment building. These buildings are interconnected as follows. The Seismic Category I auxiliary building is contiguous with the nonseismic service building on the west side. The Seismic Category I intermediate building adjoins the seismically analyzed turbine building to the north and the auxiliary building to the south. The turbine building adjoins the Seismic Category I diesel generator building to the north and the Seismic Category I control building to the south. The facade, a cosmetic rectangular structure that encloses the containment building, has all four sides partly or totally in common with the auxiliary and intermediate buildings. The auxiliary building adjoins the Seismic Category I standby auxiliary feedwater building on the south.

In the original building analysis, each Seismic Category I structure was treated independently. During the SEP plant evaluation, it was found that the interconnection nature of the buildings was an important feature, especially in view of the lack of detailed original seismic design information. Therefore, both Seismic Category I and nonseismic category buildings were included in a complicated three-dimensional structural system reanalysis model. As part of this effort, the interconnected turbine building was determined to be capable of withstanding safe shutdown earthquake forces. Based on the SEP review, audits, and plant inspections, the NRC SERs found acceptable the evaluation and resolution of SEP Topics III-2, Wind and Tornado Loadings; III-4.A, Tornado Missiles; III-6, Seismic Design Considerations; and III-7.B, Load Combinations. The NRC also concluded that the RG&E analysis and implementation of the Structural Upgrade Program were acceptable.

Below grade, the auxiliary building is primarily concrete. Above grade, the building has two roofs constructed of steel beam and bracing systems and supported by a steel frame bracing system. Insulated siding is used for most of the walls above the operating floor. The south side of the building has a combination of concrete block finished with architectural brick and siding, while portions of the east and north sides contain concrete block and siding. The low roof section of the auxiliary building parapets has been provided with scuppers designed to ensure that any rainwater, resulting from a design-basis storm, would not accumulate on the roofs and cause overload. The scuppers are located so that their outflow will not damage any surrounding plant structures. The roofing and siding provide weather resistance and allow habitability control but are not designed to be wind or tornado missile resistant.

The structure has a concrete basement floor that rests on a sandstone foundation at elevation 235 feet 8 inches, and two reinforced concrete floors, an intermediate floor at elevation 253 feet and an operating floor at elevation 271 feet. The refueling water storage tank extends through all three levels. The intermediate and operating level floors have a minimum thickness of 1 ½ feet, and are supported by 2 ½-feet-thick concrete walls at the south, east, and part of the north sides of the building. There are a number of 2 ½-feet to 3 ½-feet-thick concrete shield walls and compartments located on the floors.

The northwest corner of the building is adjacent to the circular wall of the containment building. The west concrete wall, which encloses the spent fuel storage pool, is 6 feet thick. The spent fuel storage pool, located in the auxiliary building, is a rectangular concrete structure lined with stainless steel. It contains approximately 255,000 gallons of borated water. A fuel transfer penetration is provided for fuel movement between the refueling transfer canal in the reactor containment and the SFP. The penetration consists of a stainless steel pipe installed inside a larger pipe. The inner pipe acts as the transfer tube and connects the reactor refueling canal with the SFP. The tube is fitted with a standard stainless steel flange in the refueling canal and a stainless steel sluice gate valve in the SFP. The outer pipe is welded to the containment liner, and provision is made for gas leak testing of all welds essential to the integrity of the penetration. The gasketed expansion joint accommodates motion of the sleeve within the containment shell relative to the portion of the sleeve anchored in the wall of the refueling canal in the auxiliary building. The expansion bellows inside the auxiliary building perform the same function as described for that within the containment.

The west end of the auxiliary building superstructure is connected with a portion of the service building and on the northwest with the intermediate building. The major structures of the Ginna Station have experienced no visible evidence of settlement since their construction. During the SEP and evaluation of Topic II-4.F, Settlement of Foundations and Buried Equipment, the NRC concluded that the settlement of foundations and buried equipment is not a safety concern for Ginna. In addition to structural and load-bearing elements, the auxiliary building contains features and appurtenances credited in the licensing basis and relied upon to ensure the health and safety of the public.

In addition to the equipment noted above, the auxiliary building contains racks, panels, electrical enclosures, equipment supports, fire doors, penetration barriers, and seals. Those equipment sets receive a separate commodity group evaluation independent of the building evaluation. Building interior floor drains are evaluated within the waste disposal system and the nonbuilding elements of the cranes are evaluated in the cranes, hoists, and lifting devices evaluation or the fuel handling equipment review, as appropriate.

Table 2.4.2-1 lists 15 structural component groups requiring an AMR, provides a reference to the results of the AMR for each component group, and identifies the following intended functions that these structural component groups provide:

- structural support for nonsafety-related equipment
- structural support for safety-related equipment
- pipe-whip restraint
- shelter/protection of equipment
- pressure boundary
- flood barrier
- fire barrier
- high-energy line break barrier
- missile barrier

2.4.2.1.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.1 and UFSAR Section 3.8.4 to determine whether there is reasonable assurance that the auxiliary building structural components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In its performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Table 2.4.2-1 of the LRA lists the following 15 structural component groups that require an AMR:

(1) AAD86 (structural support for safety-related equipment)

(2) AB-ARCH-EXT (non-load-bearing building elements not relied upon in the safety analysis which provide normal habitability control and weatherproofing (e.g., building siding, built-up roof systems, windows, etc.))

(3) AB-BLOCK-EXT (masonry block walls and mortar of the auxiliary building exposed to the weather)

(4) AB-BLOCK-INT (masonry block walls and mortar of the auxiliary building protected from the weather)

(5) AB-C-BUR (concrete in the auxiliary building that is in contact with the soil and ground water; embedded steel, reinforcement, and the embedded portion of anchor bolts; elastomer sealing material used below grade; post-construction urethane foam resin injected into seams and cracks to prevent ground water intrusion)

(6) AB-C-EXT (concrete in the auxiliary building that is exposed to the weather; embedded steel, reinforcement, and the embedded portion of anchor bolts; post-construction urethane foam resin injected into seams and cracks to prevent ground water intrusion)

(7) AB-C-INT (concrete in the auxiliary building that is protected from the weather including the spent fuel pool; embedded steel, reinforcement, and the embedded portion of anchor bolts and grout under column base plates)

(8) AB-ELAST-INT (elastomer sealing material used in the auxiliary building that is protected from the weather)

(9) AB-FAST(CS)-EXT (the exposed portion of carbon steel threaded fasteners for the auxiliary building that is exposed to the weather)

(10) AB-FAST(CS)-INT (the exposed portion of carbon steel threaded fasteners in the auxiliary building that is protected from the weather)

(11) AB-SS(CS)-EXT (carbon structural steel in the auxiliary building frame that is exposed to the weather)

(12) AB-SS(CS)-INT (carbon structural steel of the auxiliary building that is protected from the weather; columns, posts, beams, baseplates, bracing, crane support girders, crane rails, and the exposed faces of plates and structural members)

(13) flood barrier

(14) flood barrier-seal (bladder for flood barrier)

(15) tank (local air flask dedicated for inflating flood barrier pneumatic seals)

Since the terms “threaded fasteners” and “anchor bolts” have been used interchangeably in several tables in Section 2.4 of the LRA, the staff requested the applicant, in RAI 2.4-2, to clarify whether the terms refer to the same item. The applicant responded to RAI 2.4-2 as follows:

> Although the terms “threaded fasteners” and “anchor bolts” are different terms, the exposed portion of the structural anchor bolt receives the same evaluation as threaded fasteners. This is explained in the LRA within the descriptions for the component groups. For example: See the description for the component group "AB-C-EXT" in LRA Table 2.4.21.

The staff has reviewed the information in LRA Section 2.4.2.1, the UFSAR, and the additional information submitted by the applicant in response to the staff’s RAI. The staff finds that the applicant made no omissions in scoping and screening the auxiliary building for license renewal.

2.4.2.1.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's responses to the staff's RAIs to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified the structural components of the auxiliary building that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified the structural components of the auxiliary building that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.2 Intermediate Building

2.4.2.2.1 Summary of Technical Information in the Application

The applicant described the turbine and service building in LRA Section 2.4.2.2 and provided a list of components subject to an AMR in LRA Table 2.4.2-2.

The intermediate building is a Seismic Category I multi-story steel frame structure measuring approximately 136 feet by 141 feet. The building includes a facade structure on each side. The intermediate building surrounds the containment building to the west and north and joins the service building, turbine building, and auxiliary building. It is divided into two sections called the hot side (restricted area access) and the cold side. The intermediate building houses and supports safety-related equipment. Portions of the structure act as fire barriers. Structural elements within the building, along with the ability to open selected doors, are factors considered for heat removal during SBO events. Additionally, the building contains nonsafety elements whose failure can affect a safety function (portions of the structure are designed to resist HELB and flooding).

The intermediate building is part of a complex of interconnected buildings surrounding, but structurally independent of, the containment building. The building is a 136 feet 7 inches by 140 feet 11 inches steel frame structure with facade structures on each side. The columns have individual concrete footings embedded in the rock foundation. In the south part of the building there are two floors at elevations 271 feet and 293 feet, and the low roof at elevation 318 feet. All floors are made of composite steel girders and 5-inch thick concrete slabs. Built around the circular containment building, the floors extend completely through the west side of the intermediate building, a major portion of the north side, and a small portion of the south side. There are no floors on the east side. The roof is supported by steel roof girders. The floors and roof are also supported vertically on a set of interior steel columns, which are continuous from the basement floor to the roof. Concrete block walls surround the floor space between the basement floor and the roof. The roof of the intermediate building has been provided with scuppers designed to ensure that any rainwater, resulting from a design-basis storm, would not accumulate on the roof and cause damage. The scuppers are located so that their outflow will not damage any surrounding plant structures. The roofing and exterior walls provide weather resistance and allow habitability control but are not designed to be tornado missile resistant. In addition to the structural and load-bearing elements, the intermediate building contains the following features and appurtenances credited in the licensing basis and relied upon to ensure the health and safety of the public:

- a fire-resistant enclosure at the cable tunnel entrance to the intermediate building to separate trains of safe shutdown equipment

- grating versus solid manway covers in the access holes between the cold side of the intermediate building and the building subbasement to provide a dewatering path in the event of a line break

- jet impingement shielding on the floor under the main steam header

- missile shields to protect vital cable trays from possible TDAFW pump turbine missiles

- jet impingement shields affixed to the containment wall to separate between vital instruments

- jet impingement and missile shielding around the solenoid valves for the main steam isolation valves

- sealing material between the intermediate building/containment building rattle gaps to prevent cross communication of flood volumes

- restraining devices installed at the intermediate building/turbine building interface (above the main steam power- operated relief valves) to ensure that a block wall failure will not damage the valves

- scuppers installed in the building roof to ensure water cannot build up and overload roof members

- building foundations and below-grade walls constructed with water stops to prevent the intrusion of ground water

- an oil containment dike around the TDAFW lube oil tank to minimize the fire risk from any spilled oil

- selected structural steel building members coated with a protective material to resist the effects of fires

- specially constructed radiation shielding enclosures to minimize personnel dose during post accident sampling evolutions

- a standby auxiliary feedwater system added to further improve steam generator feedwater reliability and specifically to substitute for the preferred auxiliary feedwater in the low probability that preferred auxiliary feedwater pumps are damaged due to nearby high-energy pipe breaks within the intermediate building

In addition to these features, the intermediate building contains racks, panels, electrical enclosures, equipment supports, fire doors, penetration barriers, and seals. These equipment sets receive a separate commodity group evaluation independent of the building evaluation. The restricted access portion of the building's interior floor drains is evaluated with the waste disposal system, and the unrestricted access portion is evaluated in the discussion of the treated water system.

Table 2.4.2-2 of the LRA lists 12 structural component groups requiring an AMR, provides a reference to the results of the AMR for each component group, and identifies the following intended functions for these structural component groups:

- structural support for nonsafety-related equipment
- structural support for safety-related equipment
- shelter/protection of equipment
- flood barrier
- fire barrier
- high-energy line break barrier
- missile barrier
- heat sink

2.4.2.2.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.2 and UFSAR Section 3.8.4 to determine whether there is reasonable assurance that the intermediate building structural components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of its review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Table 2.4.2-2 of the LRA lists the following 12 structural component groups that require an AMR:

(1) IB-ARCH-EXT (non-load-bearing building elements not relied upon in the safety analysis which provide normal habitability control and weatherproofing (e.g., building siding, built-up roof systems, windows, etc.))

(2) IB-BLOCK-EXT (masonry block walls and mortar of the intermediate building exposed to the weather)

(3) IB-BLOCK-INT (masonry block walls and mortar of the intermediate building that are protected from the weather)

(4) IB-C-BUR (concrete in the intermediate building that is in contact with the soil and groundwater; embedded steel, reinforcement, and the embedded portion of anchor bolts; elastomer sealing material used below grade in the intermediate building; post-construction urethane foam resin injected into seams and cracks to prevent ground water intrusion)

(5) IB-C-EXT (concrete in the intermediate building that is exposed to the weather; embedded steel, reinforcement, and the embedded portion of anchor bolts)

(6) IB-C-INT (concrete in the intermediate building that is protected from the weather; embedded steel, reinforcement, and the embedded portion of anchor bolts; grout used under column base plates)

(7) IB-ELAST-INT (elastomer sealing material used in the intermediate building that is protected from the weather)

(8) IB-FAST(CS)-EXT (the exposed portion of carbon steel threaded fasteners for the intermediate building that are exposed to the weather)

(9) IB-FAST(CS)-INT (the exposed portion of carbon steel threaded fasteners in the intermediate building that are protected from the weather)

(10) IB-LEAD-INT (the shielded enclosure constructed over the primary sample containment isolation valves in the intermediate building hot side; leaded glass and lead bricks)

(11) IB-SS(CS)-EXT (carbon structural steel in the intermediate building frame that is exposed to the weather)

(12) IB-SS(CS)-INT (carbon structural steel in the intermediate building that is protected from the weather; columns, posts, beams, baseplates, bracing, and the exposed faces of plates and structural members)

The staff has reviewed the information in LRA Section 2.4.2.2 and the UFSAR. The staff finds that the applicant made no omissions in scoping and screening the intermediate building for license renewal.

2.4.2.2.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant’s response to the staff’s RAI to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified the structural components of the intermediate building that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified the structural components of the intermediate building that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.3 Turbine Building

2.4.2.3.1 Summary of Technical Information in the Application

The applicant described the turbine building in LRA Section 2.4.2.3 and provided a list of components subject to an AMR in LRA Table 2.4.2-3.

Though the turbine building was not originally designed to be Seismic Category I, it is part of a complex of interconnected buildings and is connected to Seismic Category I structures. As such, the turbine building is considered a structure that supports nuclear safety-related equipment. Subsequently, the turbine building has been modified and reevaluated to be capable of withstanding safe shutdown earthquake forces. Portions of the turbine building structure also act as fire barriers and oil confinement systems. Additionally, the building contains nonsafety elements whose failure can affect a safety function (portions of the structure are designed to resist, and protect equipment from, HELBs, flooding, and tornadoes). During the SEP plant evaluation, it was determined that the interconnected turbine building was capable of withstanding safe shutdown earthquake forces.

The turbine building is a 257 ½ feet by 124 ½ feet rectangular building on the north side of the building complex. The turbine building foundation is a concrete mat supported by compacted fill material. In addition to the concrete basement, it has two concrete floors. The building roof includes a roof truss structure composed of top and bottom chords connected by vertical bracing. The roof and floors are supported by steel framing and bracing systems on all four sides of the building. Except between buildings, the walls of the turbine building have insulated siding. The turbine building parapets have been provided with scuppers designed to ensure that any rainwater, resulting from a design-basis storm, would not accumulate on the roof and cause damage. The scuppers are located so that their outflow will not damage any surrounding plant structures. The roofing and siding provide weather resistance and allow habitability control but are not designed to be tornado missile resistant.

For the purposes of license renewal review, the walls separating the turbine building from the intermediate building, the diesel generator building, the service building, the control building and the AVT building will be evaluated as part of the review of these structures as appropriate. Additionally, the main feedwater pumps are surrounded by a block wall enclosure. In addition to the structural and load-bearing elements, the turbine building contains the following features and appurtenances credited in the licensing basis and relied upon to ensure the health and safety of the public:

- The turbine building includes a barrier installed around the turbine lube-oil reservoir area to contain possible oil spillage.

- Selected structural steel building members are coated with a protective material to resist the effects of fires.

- Some building structural members also interface with the pressure-shielding steel diaphragm walls that were installed at the control building-turbine building wall and at the diesel building-turbine building wall to ensure continued operability of safety-related equipment following a postulated high-energy pipe break in the turbine building.

- The turbine seal oil unit is enclosed in a fire-resistant shelter.

- The building foundations and below-grade walls were constructed with water stops to prevent the intrusion of ground water.

The turbine building contains racks, panels, electrical enclosures, equipment supports, fire doors, penetration barriers, seals, and coatings. These equipment sets receive a separate commodity group evaluation independent of the building evaluation.

Table 2.4.2-3 of the LRA lists eight structural component groups requiring an AMR, provides a reference to the results of the AMR for each component group, and identifies the following intended functions that these structural component groups provide:

- structural support for nonsafety-related equipment
- structural support for safety-related equipment
- shelter/protection of equipment

2.4.2.3.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.3 and UFSAR Section 3.8.4 to determine whether there is reasonable assurance that the structural components of the turbine building within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of its review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Table 2.4.2-3 of the LRA lists eight structural component groups that require an AMR as follows:

(1) TB-ARCH-EXT (non-load-bearing building elements not relied upon in the safety analysis which provide normal habitability control and weather proofing (e.g., building siding, built up roof systems, windows, etc.))

(2) TB-C-BUR (concrete in the turbine building that is in contact with the soil and ground water; embedded steel, reinforcement, and the embedded portion of anchor bolts; elastomer sealing material used below grade in the turbine building; post-construction urethane foam resin injected into seams and cracks to prevent ground water intrusion)

(3) TB-C-EXT (concrete exposed to the weather that acts as part of the building siding system; non-load-bearing building elements not relied upon in the safety analysis which provide normal habitability control and weather proofing (e.g., building siding, built up roof systems, windows, etc.))
(4) TB-C-INT (concrete in the turbine building that is protected from the weather, including oil confinement curbing around the seal oil unit; embedded steel, reinforcement, and the embedded portion of anchor bolts; grout used under column base plates)

(5) TB-FAST(CS)-EXT (the exposed portion of carbon steel threaded fasteners for the turbine building that is exposed to the weather)

(6) TB-FAST(CS)-INT (the exposed portion of carbon steel threaded fasteners in the turbine building that are protected from the weather)

(7) TB-SS(CS)-EXT (carbon structural steel in the turbine building frame that is exposed to weather)

(8) TB-SS(CS)-INT (carbon structural steel of the turbine building that is protected from the weather; columns, posts, beams, baseplates, bracing, crane support girders, crane rails, and the exposed faces of plates and structural members)

The staff has reviewed the information in LRA Section 2.4.2.3 and the UFSAR. The staff finds that the applicant made no omissions in scoping and screening the turbine building for license renewal.

2.4.2.3.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant’s response to the staff’s RAI to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified the structural components of the turbine building that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified the structural components of the turbine building that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.4 Diesel Building

2.4.2.4.1 Summary of Technical Information in the Application

The applicant described the diesel building in LRA Section 2.4.2.4 and provided a list of components subject to an AMR in LRA Table 2.4.2-4.

The diesel building is a Seismic Category I structure that houses and supports nuclear safety-related equipment. The diesel building also protects connections for an alternate diesel cooling water source should the SW system be disabled. The structure also acts as a fire barrier and contains nonsafety elements whose failure can affect a safety function (portions of the structure are designed to resist, and protect equipment from, HELBs, flooding, and tornadoes).

The diesel building is part of a complex of interconnected buildings surrounding, but structurally independent of, the containment building. The diesel building is a one-story reinforced-concrete structure divided into two rooms, each with a cable vault underneath the floor. The south wall, which is common with the turbine building, is reinforced to be a pressurization wall to protect the areas adjacent to the turbine building from the effects of HELBs. The foundations of the diesel generator buildings were excavated to the surface of bedrock. Lean concrete or compacted backfill was placed on the rock surface to a depth such that the elevation of the top of the fill material was coincident with the elevation of the bottom of the concrete foundation.

The diesel building was modified as part of the Structural Upgrade Program to withstand tornado winds and missiles, external flooding, seismic loads, and extreme snow loads. A new reinforced-concrete north wall was constructed 4 feet north of the existing north wall. Reinforced-concrete wing walls were constructed that extended the east and west walls to meet the new north wall, enclosing the space between the existing and new north wall. The new wall includes missile-resistant watertight equipment and personnel doors. A new reinforced-concrete slab roof with a reinforced-concrete parapet was constructed covering the entire diesel building. The building as modified was designed to remain undamaged during and after an operating basis earthquake and remain functional during and after a safe shutdown earthquake. In addition to structural and load bearing elements, the diesel building contains features and appurtenances credited in the licensing basis and relied upon to ensure the health and safety of the public, as follows:

- The B diesel room vault contains a fire-resistant enclosure to provide electrical train separation.

- The building foundations and below-grade walls were constructed with water stops to prevent the intrusion of ground water.

- The common wall between the diesel building and turbine building is reinforced with heavy sheet piling and stiffeners to form a pressurization wall to resist the effects of a HELB in the turbine building.

- The diesel building exterior was modified during the Structural Upgrade Program to withstand the effects of tornado wind, tornado differential pressure, tornado missiles, and flooding of Deer Creek.

- Scuppers are installed in the building roof to ensure water cannot build up and overload roof members.

The diesel building contains sump pumps to remove any ground water that may leak into the vaults. This equipment is not considered part of the structure and is evaluated with the treated water system. The building also contains racks, panels, electrical enclosures, equipment supports, fire doors, penetration barriers, and seals. These equipment sets receive a separate commodity group evaluation independent of the building evaluation.

Table 2.4.2-4 of the LRA lists 12 structural component groups requiring an AMR, provides a reference to the results of the AMR for each component group, and identifies the following intended functions for these structural component groups:

(1) structural support for nonsafety-related equipment
(2) structural support for safety-related equipment
(3) shelter/protection of equipment
(4) flood barrier
(5) fire barrier
(6) high-energy line break barrier
(7) missile barrier

2.4.2.4.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.4 and UFSAR Section 3.8.4 to determine whether there is reasonable assurance that the diesel building structural components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of its review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Table 2.4.2-4 of the LRA lists the following 12 structural component groups that require an AMR:

(1) DB-ARCH-EXT (non-load bearing building elements not relied upon in the safety analysis which provide normal habitability control and weatherproofing (e.g., building siding, built up roof systems, windows, etc.))

(2) DB-C-BUR (concrete in the diesel building that is in contact with the soil and ground water; embedded steel, reinforcement, and the embedded portion of anchor bolts; elastomer sealing material used below grade in the diesel generator building; post-construction urethane foam resin injected into seams and cracks to prevent ground water intrusion)

(3) DB-C-EXT (concrete in the diesel generator building that is exposed to the weather; embedded steel, reinforcement, and the embedded portion of anchor bolts)

(4) DB-C-INT (concrete in the diesel generator building that is protected from the weather; embedded steel, reinforcement, and the embedded portion of anchor bolts; grout used under column base plates)

(5) DB-ELAST-INT (elastomer sealing material used in the door seals for the diesel generator building that is protected from the weather)

(6) DB-FAST(CS)-EXT (the exposed portion of carbon steel threaded fasteners for the diesel generator building that is exposed to the weather)

(7) DB-FAST(CS)-INT (the exposed portion of carbon steel threaded fasteners in the diesel generator building that is protected from the weather)

(8) DB-FAST(HSLAS)-INT (the exposed portion of high-strength carbon steel threaded fasteners in the diesel generator building that is protected from the weather)

(9) DB-SS(CS)-EXT (structural carbon steel in the diesel generator building (e.g., missile barriers, that is exposed to the weather))

(10) DB-SS(CS)-INT (structural carbon steel for the diesel generator building (e.g., plates, beams, columns, grating, high-energy line break pressurization wall, etc.) that is protected from the weather)

(11) EXT-DOOR (carbon steel exterior doors that resist tornados and floods)

(12) INT-DOOR (carbon steel interior doors that resist high-energy line breaks and floods)

The staff has reviewed the information in LRA Section 2.4.2.4 and the UFSAR. The staff finds that the applicant made no omissions in scoping and screening the diesel generator building for license renewal.

2.4.2.4.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's response to the staff's RAI to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified the structural components of the diesel building that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified the structural components of the diesel building that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.5 Control Building

2.4.2.5.1 Summary of Technical Information in the Application

The applicant described the control building in LRA Section 2.4.2.5 and provided a list of components subject to an AMR in LRA Table 2.4.2-5.

The control building is a Seismic Category I three-story structure measuring approximately 41 feet by 54 feet. It is located north of the containment building and adjacent to the turbine building. The control building houses and supports the safety-related control room, vital battery rooms, the relay room, and the mechanical equipment room. These rooms provide power and controls for the ESF equipment and most other equipment required for plant operation. The control room portion of the control building functions in concert with the control room emergency air treatment ventilation equipment to maintain a habitable environment for plant operators during design-basis events. Portions of the structure act as fire barriers. Some structural elements of the building are credited with providing a heat sink to ensure that vital equipment can function for the required coping duration of an SBO. Additionally, the building contains nonsafety elements whose failure can affect a safety function (portions of the structure are designed to resist, and protect equipment from, HELBs, flooding, and tornadoes).

The control building is part of a complex of interconnected buildings surrounding, but structurally independent of, the containment building. The foundation of the control building is supported on lean concrete or compacted backfill. The foundation of the control building was excavated to the surface of the bedrock. The fill material was placed on the rock surface to a depth coincident with the control building foundation. The roof of the control building has a parapet provided with a scupper designed to ensure that any rainwater, resulting from a design-basis storm, will not accumulate on the roof and cause damage. The scupper is located so that its outflow will not damage any surrounding plant structures or equipment.

The control room floor and the relay room floor are 6-inch thick reinforced-concrete slabs supported by steel girders that are tied to turbine building floors at the respective elevations. The relay room east interior wall is primarily insulated siding and some concrete block. The east relay room exterior wall was installed during the Structural Upgrade Program and is designed to withstand the effects of tornado wind, tornado differential pressure, tornado missiles, and flooding of Deer Creek. The modification consisted of installing a reinforced-concrete Seismic Category I structure adjoining the east wall of the relay room. The entire north wall of the control building is protected from the effects of a HELB in the turbine building by a steel barrier. In the basement of the structure are the battery rooms and the control building mechanical equipment room. Analysis concluded that a failure in the SW system or fire main system in the mechanical equipment room was capable of flooding both battery rooms. To preclude that event, the original door between the air handling room and the B battery room has been replaced by a wall and a water relief valve has been installed between the mechanical equipment room and the turbine building. The relief valve will ensure that the room can de-water sufficiently to prevent wall collapse.

The control room portion of the structure acts in conjunction with the control room ventilation system as part of the control room emergency air treatment system (CREATS). The control room's role is to provide a non-leak-tight pressure boundary envelope to support emergency air treatment. The CREATS boundary encompasses the entire room interior boundary, including the room access doors. The false ceiling is not included in the CREATS boundary but the structural ceiling and the room's interface with the ventilation ductwork are. The false ceiling panels are nonsafety equipment whose failure can affect a safety function, and they are seismically restrained. Additionally, the panels can be removed during SBO events in order to allow optimum heat transfer to the structural members.

In addition to structural and load-bearing elements, the control building contains the following features and appurtenances credited in the licensing basis and relied upon to ensure the health and safety of the public:

- The common wall between the control building and turbine building is reinforced with heavy sheet piling and stiffeners that form a pressurization wall to resist the effects of a high-energy line break in the turbine building.

- The north and east wall of the control room has a 1/4-inch armor plate to resist the effects of tornado missiles and malicious acts.

- The east wall of the relay room was modified during the Structural Upgrade Program to withstand the effects of tornado wind, tornado differential pressure, tornado missiles, and flooding of Deer Creek.

- Scuppers are installed in the building parapet to ensure that water cannot build up and overload roof members.

- Selected below-grade construction joints, seams, and cracks are sealed to prevent ground-water intrusion.

- Battery room and mechanical equipment room doors at the turbine building entrances are elevated to preclude water intrusion into the rooms from floods.

- A barrier exists at the cable tunnel entrance to the control building to provide fire area separation.

- Selected structural steel building members are coated with a protective material to resist the effects of fires.

- Design configuration control is strictly maintained to ensure that the building structural features credited in heat sink calculations for station blackout are maintained.

- The south and west above-grade concrete walls provide radiation shielding for plant operators.

- Block walls were evaluated and upgraded as necessary to ensure their continued functioning during a design-basis earthquake.

- The building foundations and below-grade walls were constructed with water stops to prevent the intrusion of ground water.

In addition to the equipment noted above, the control building contains racks, panels, electrical enclosures, equipment supports, fire doors, penetration barriers, and seals. These equipment sets receive a separate commodity group evaluation independent of the building evaluation. Building interior floor drains are evaluated as part of the treated water system.

Table 2.4.2-5 of the LRA lists 15 structural component groups requiring an AMR, provides a reference to the results of the AMR for each component group, and identifies the following intended functions for these structural component groups:

(1) structural support for safety-related equipment
(2) shelter/protection of equipment
(3) flood barrier
(4) fire barrier
(5) high-energy line break barrier
(6) missile barrier
(7) heat sink
(8) radiation/heat shielding

2.4.2.5.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.5 and UFSAR Section 3.8.4 to determine whether there is reasonable assurance that the control building structural components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Table 2.4.2-5 of the LRA lists the following 15 structural component groups that require an AMR:

(1) CB-ARCH-EXT (non-load-bearing building elements not relied upon in the safety analysis which provide normal habitability control and weatherproofing (e.g., building siding, built-up roof systems, windows, etc.))

(2) CB-BLOCK-INT (masonry block walls and mortar of the control building that are protected from the weather)

(3) CB-C-BUR (concrete in the control building that is in contact with the soil and ground water; embedded steel, reinforcement, and the embedded portion of anchor bolts; elastomer sealing material used below grade in the control building; post-construction urethane foam resin injected into seams and cracks to prevent ground water intrusion)

(4) CB-C-EXT (concrete in the control building that is exposed to the weather; embedded steel, reinforcement, and the embedded portion of anchor bolts)

(5) CB-C-INT (concrete in the control building that is protected from the weather; embedded steel, reinforcement, and the embedded portion of anchor bolts; grout used under column base plates)

(6) CB-ELAST-INT (elastomer sealing material for door seals and the dewatering valve closure seal used in the control building that is protected from the weather)

(7) CB-FAST(CS)-EXT (the exposed portion of carbon steel threaded fasteners for the control building that are exposed to the weather)

(8) CB-FAST(CS)-INT (the exposed portion of carbon steel threaded fasteners in the control building that is protected from the weather)

(9) CB-FAST(HSLAS)-INT (the exposed portion of high-strength carbon steel threaded fasteners in the control building that is protected from the weather)

(10) CB-SS(CS)-EXT (carbon structural steel in the control building frame that is exposed to the weather)

(11) CB-SS(CS)-INT (carbon structural steel in the control building that is protected from the weather; columns, posts, beams, baseplates, bracing, and the exposed faces of plates and structural members)

(12) S51F (the carbon steel interior door to resist high-energy line breaks, and along with the water curtain, to provide a fire barrier)

(13) EXT-DOOR (the carbon steel interior doors to resist high-energy line breaks and floods)

(14) INT-DOOR (the carbon steel interior doors to resist high-energy line breaks)

(15) VALVE BODY (the valve to dewater the control building in the event of a service water or fire water line break in the mechanical equipment room)

The staff has reviewed the information in LRA Section 2.4.2.5 and the UFSAR. The staff finds that the applicant made no omissions in scoping and screening the control building for license renewal.

2.4.2.5.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's response to the staff's RAI to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified the structural components of the control building that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified the structural components of the control building that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.6 All-Volatile Water Treatment Building

2.4.2.6.1 Summary of Technical Information in the Application

The applicant described the all-volatile water treatment building in LRA Section 2.4.2.6 and provided a list of components subject to an AMR in LRA Table 2.4.2-6.

The AVT building is a nonseismic structure that houses NNS equipment considered important to safety. Specifically, the AVT building houses and supports the TSC diesel generator and battery which may be used to mitigate the effects of fires and SBOs. Additionally, building walls act as fire barriers. Accordingly, the AVT building is considered a nonsafety structure whose failure could affect a safety function. The AVT building houses demineralizers and other equipment necessary for the condensate polishing system to allow AVT of secondary water. The TSC is located on the second floor of the AVT building and houses the computers and equipment, including emergency power supplies (diesel generator and batteries), necessary to provide the staff with technical support during an emergency event.

The AVT building is founded on a concrete mat. The building abuts the turbine building at the east end of the turbine building. A small section of masonry block separates the turbine building from the AVT building. Some exterior portions of the east and north sides of the structure are masonry block. The load-bearing portions of the building include steel support framing and reinforced concrete. Select portions of the bottom floor of the building have 2-feet thick concrete walls and ceiling to minimize operator exposure in case of radioactivity buildup in the resin beds should a steam generator tube leak occur. The building's concrete roof is supported by steel decking and trusses.

The AVT building is not designed to be resistant to high winds or tornado missiles. The technical support center is above the maximum external flood water level. The AVT building contains racks, panels, electrical enclosures, equipment supports, fire doors, penetration barriers, and seals. Those equipment sets receive a separate commodity group evaluation independent of the building evaluation. Building interior floor drains are evaluated as part of the treated water system.

Table 2.4.2-6 of the LRA lists six structural component groups requiring an AMR, provides a reference to the results of the AMR for each component group, and identifies the following intended functions for these structural component groups:

- structural support for nonsafety-related equipment
- shelter/protection of equipment
- fire barrier

2.4.2.6.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.6 and the UFSAR to determine whether there is reasonable assurance that the all-volatile water treatment building structural components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Table 2.4.2-6 of the LRA lists the following eight structural component groups that require an AMR:

(1) AVT-ARCH-EXT (non-load-bearing building elements not relied upon in the safety analysis which provide normal habitability control and weatherproofing (e.g., building siding, built-up roof systems, windows, etc.))

(2) AVT-BLOCK-EXT (masonry block and mortar exposed to the weather that acts as part of the building siding system; non-load-bearing building elements not relied upon in the safety analysis which provide normal habitability control and weatherproofing (e.g., building siding, built-up roof systems, windows, etc.))

(3) AVT-BLOCK-INT (masonry block walls and mortar of the AVT/TSC building protected from the weather)

(4) AVT-C-BUR (concrete in the AVT/TSC building that is in contact with the soil and ground water; embedded steel, reinforcement, and the embedded portion of anchor bolts; elastomer sealing material used below grade in the AVT/TSC building; post-construction urethane foam resin injected into seams and cracks to prevent ground water intrusion)

(5) AVT-C-EXT (concrete in the AVT/TSC building that is exposed to the weather; embedded steel, reinforcement, and the embedded portion of anchor bolts)

(6) AVT-C-INT (concrete in the AVT/TSC building that is protected from the weather; embedded steel, reinforcement, and the embedded portion of anchor bolts; grout under column base plates; the fuel oil confinement curb for the TSC diesel)

(7) AVT-FAST(CS)-INT (the exposed portion of carbon steel threaded fasteners in the AVT/TSC building that is protected from the weather)

(8) AVT-SS(CS)-INT (structural carbon steel of the AVT/TSC building that is protected from the weather; columns, posts, beams, baseplates, bracing, crane support girders, crane rails, and the exposed faces of plates and structural members)The staff has reviewed the information in LRA Section 2.4.2.6. The staff finds that the applicant made no omissions in scoping and screening the AVT building for license renewal.

2.4.2.6.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's response to the staff's RAI to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified the structural components of the AVT building that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified the structural components of the AVT building that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.7 Screenhouse Building

2.4.2.7.1 Summary of Technical Information in the Application

The applicant described the screenhouse building in LRA Section 2.4.2.7 and provided a list of components subject to an AMR in LRA Table 2.4.2-7.

The screenhouse building is partially a Seismic Category 1 structure. It is located north of the turbine building and is not immediately adjacent to any other major structure. The screenhouse structurally supports and houses safety-related equipment, including equipment used to mitigate fires and components used for safe shutdown following fires and SBO events. Included within the screenhouse evaluation boundary is the CW system discharge canal which functions to ensure the availability of essential SW from the ultimate heat sink. Additionally, the screenhouse also contains nonsafety equipment whose failure could prevent the satisfactory accomplishment of a safety function (internal flood protection). The screenhouse is located 115 feet north of the turbine building and 80 feet south of the lake shore. The structural configuration of the screenhouse is integral to the functioning of the SW system, the CW system and the FP system. The below-grade and submerged portions of the structure make available the flow path from the ultimate heat sink to the referenced system pump suctions. Should the CW system intake tunnels be lost, the structure supports provisions for an alternate lake suction path by providing a flow path from the discharge canal to the SW and fire system water pump bay. The components supporting this feature are evaluated within the SW system.

The screenhouse building comprises two structural steel superstructures, one on the SW system side and one on the CW system side. The superstructures share a reinforced concrete substructure. The SW portion of the building (both below and above grade) is a Seismic Category I structure. The SW portion houses four safety-related SW pumps and safety-related electric switchgear. The CW side houses the traveling water screens and CW pumps. The entire screenhouse SW building is founded in or on bedrock with the exception of the basement of the SW portion, which is founded approximately 4 feet above bedrock. The SW portion of the screenhouse consists of four rigid frame bents in the east-west direction, with bracing for wind and seismic loads in the north-south direction. The roof system is designed as a rigid bent to transmit horizontal seismic loads to the frame columns and through the bracing to the foundation. Insulated siding is used for most of the walls above the operating floor. The exterior walls contain windows, doors, and louvered ventilation openings. The roof has been provided with scuppers designed to ensure that any rainwater, resulting from a design-basis storm, would not accumulate on the roofs and cause damage. The roofing and siding provide weather resistance and allow habitability control but are not designed to be resistant to tornado missiles.

The screenhouse building is not designed to resist or protect housed components against all possible external flooding, high wind, fire, or high- or moderate- energy line break events. Complete protection against these low probability events is not needed because alternative shutdown means are available, which do not rely upon service water from the screenhouse. In the SER for SEP Topic III-5.B, Pipe Breaks Outside Containment, the NRC concluded that any further modification of the screenhouse to provide additional protection from pipe break effects for SW system components, or for buses 17 and 18, is not required. The mitigative strategy developed and approved for pipe breaks was subsequently applied with respect to external flooding and tornado events. After completion of the Structural Upgrade Program, the NRC concluded that the station could achieve safe shutdown given the effects of loss of the screenhouse because of external events.

The discharge canal, included in the screenhouse evaluation boundary, is a reinforced concrete structure that directs CW and SW effluent back to the lake and the end of the open loop cooling cycle. As noted above, the screenhouse and discharge canal have features that provide water intake from the discharge canal to the SW system should the CW intake tunnel become unavailable. Overtopping of the discharge canal from storm effects in the lake is prevented by a revetment. The revetment is evaluated separately within the essential yard structures discussion. In addition to structural and load-bearing elements, the screenhouse contains the following features and appurtenances credited in the licensing basis and relied upon to ensure the health and safety of the public:

- Safety-related equipment is protected from flooding resulting from a break or leakage in the circulating water system. The first protective feature consists of tripping the circulating water pumps when a leak is detected. The circulating water pumps are tripped by redundant two-out-of-three logic receiving level information from the circulating water pump pit in the screenhouse and from the condenser pit in the turbine building. Electrical components that perform this function are evaluated with the reactor protection system. The second part of the flood mitigative system is a permanently installed, nonmovable Seismic Category I dike in the screenhouse, which has been built to contain the water that may escape from the circulating water system. The dike is 30 inches high and is situated to prevent water from reaching safety-related equipment.

- A curb has been installed around the diesel fire pump and the diesel oil storage tank to control any diesel oil leaks. The curbed area is equipped with a floor drain which drains to a holding tank buried outside the screenhouse.
- The building foundations and below-grade walls were constructed with water stops to prevent the intrusion of ground water.
- Cable entrances are sealed to prevent the intrusion of ground water.

The screenhouse contains racks, panels, electrical enclosures, equipment supports, fire penetration barriers, and seals. Those equipment sets receive a separate commodity group evaluation independent of the building evaluation. Building interior floor drains are evaluated with the CW system.

Table 2.4.2-7 of the LRA lists eight structural component groups requiring an AMR, provides a reference to the results of the AMR for each component group, and identifies the following intended functions for these structural component groups:

- structural support for nonsafety-related equipment
- structural support for safety-related equipment
- shelter/protection of equipment
- flood barrier
- fire barrier
- cooling water source

2.4.2.7.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.7 and UFSAR Section 3.8.4 to determine whether there is reasonable assurance that the screenhouse building structural components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Table 2.4.2-7 lists the following eight structural component groups that require an AMR:

(1) SH-ARCH-EXT (non-load-bearing building elements not relied upon in the safety analysis which provide normal habitability control and weatherproofing (e.g., building siding, built-up roof systems, windows, etc.))

(2) SH-C-BUR (concrete in the screenhouse that is in contact with the soil and ground water; embedded steel, reinforcement, and the embedded portion of anchor bolts; elastomer

sealing material used below grade in the screenhouse; post-construction urethane foam resin injected into seams and cracks to prevent ground-water intrusion)

(3) SH-C-EXT (concrete in the screenhouse that is exposed to the weather; concrete used in the discharge canal; embedded steel, reinforcement, and the embedded portion of anchor bolts)

(4) SH-C-INT (concrete in the screenhouse that is protected from the weather; interior concrete to provide flood protection curbing for the subbasement and fire protection curbing to contain diesel fuel oil spills; embedded steel, reinforcement, and the embedded portion of anchor bolts; grout under column base plates)

(5) SH-C-RW (concrete in the screenhouse that is submerged; concrete used in the discharge canal; embedded steel, reinforcement, and the embedded portion of anchor bolts)

(6) SH-ELAST-INT (elastomer sealing material used as gasketing material for flood barriers in the screenhouse that is protected from the weather)

(7) SH-FAST(CS)-INT (the exposed portion of carbon steel threaded fasteners in the screenhouse that are protected from the weather)

(8) SH-SS(CS)-INT (structural carbon steel for the screenhouse that is protected from the weather (e.g., plates, beams, columns, grating, etc.) and the barrier between the CW and SW bays to protect the SW pumps from a break in the CW system and to prevent flooding of other vital equipment)

The staff has reviewed the information in LRA Section 2.4.2.7 and the UFSAR. The staff finds that the applicant made no omissions in scoping and screening the screenhouse building for license renewal.

2.4.2.7.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant’s response to the staff’s RAI to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified the structural components of the screenhouse building that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified the structural components of the screenhouse building that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.8 Standby Auxiliary Feedwater Building

2.4.2.8.1 Summary of Technical Information in the Application

The applicant described the SAFW building in LRA Section 2.4.2.8 and provided a list of components subject to an AMR in LRA Table 2.4.2-8.

The SAFW building is a Seismic Category I high-wind and tornado-missile resistant structure located south of the auxiliary building. The SAFW building houses and supports a safety-related feedwater system that is completely diverse from the preferred auxiliary feedwater system (located in the intermediate building). The SAFW building also protects connections for an alternate pump suction source should the SW system be disabled.

The SAFW building is a concrete structure utilizing reinforced concrete for the walls, roof, and base mat. The building is supported by 12 caissons that are socketed into competent rock. The exterior of the building is sheathed with a combination of architectural brick and siding. The SAFW building does not need to be resistant to external flood because the safety-related equipment in the room is mounted above the maximum flood level. The seismic portion of the building is connected to an entryway enclosure that allows for building environmental control. In addition to structural and load-bearing elements, the SAFW building contains the following features and appurtenances credited in the licensing basis and relied upon to ensure the health and safety of the public:

- Safety-related equipment is mounted above the maximum external flood level.

- An internal missile barrier separates the A and B SAFW pumps.

- The structure provides feedwater source protected from high winds and tornado missiles.

- The structure, in conjunction with the standby auxiliary feedwater system, was added to further improve steam generator feedwater reliability and specifically to substitute for the preferred auxiliary feedwater in the low probability that preferred auxiliary feedwater pumps are damaged due to nearby high-energy pipe breaks within the intermediate building.

The SAFW building contains racks, panels, electrical enclosures, equipment supports, fire, penetration barriers, and seals. These equipment sets receive a separate commodity group evaluation independent of the building evaluation.

Table 2.4.2-8 of the LRA lists six structural component groups requiring an AMR, provides a reference to the results of the AMR for each component group, and identifies the following intended functions for these structural component groups:

- structural support for safety-related equipment
- shelter/protection of equipment
- fire barrier
- missile barrier

2.4.2.8.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.8 and UFSAR Section 3.8.4 to determine whether there is reasonable assurance that the SAFW building components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of its review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Table 2.4.2-8 of the LRA lists the following six structural component groups that require an AMR:

(1) AF-ARCH-EXT (non-load-bearing building elements not relied upon in the safety analysis which provide normal habitability control and weatherproofing (e.g., building siding, built-up roof systems, windows, etc.))

(2) AF-C-BUR (concrete in the SAFW building that is in contact with the soil and ground water; embedded steel, reinforcement, and the embedded portion of anchor bolts; elastomer sealing material used below grade in the SAFW building; post-construction urethane foam resin injected into seams and cracks to prevent ground-water intrusion)

(3) AF-C-EXT (concrete in the SAFW building that is exposed to the weather; embedded steel, reinforcement, and the embedded portion of anchor bolts)

(4) AF-C-INT (concrete in the SAFW building that is protected from the weather; embedded steel, reinforcement, and the embedded portion of anchor bolts; grout under column base plates)

(5) AF-FAST(CS)-INT (the exposed portion of carbon steel threaded fasteners in the SAFW building that is protected from the weather)

(6) AF-SS(CS)-INT (structural carbon steel in the SAFW building that is protected from the weather; columns, posts, beams, baseplates, bracing, and the exposed faces of plates and structural members)

The staff has reviewed the information in LRA Section 2.4.2.8 and the UFSAR. The staff finds that the applicant made no omissions in scoping and screening the SAFW building for license renewal.

2.4.2.8.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's response to the staffs RAI to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified the structural components of the SAFW building that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified the structural components of the SAFW building that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.9 Service Building

2.4.2.9.1 Summary of Technical Information in the Application

The applicant described the service building in LRA Section 2.4.2.9 and provided a list of components subject to an AMR in LRA Table 2.4.2-9.

The service building is a nonseismic structure that houses NNS equipment considered important to safety. Specifically, the service building houses and supports the CST which may be used to mitigate the effects of fires and SBOs and is the preferred suction source for the AFW system. Additionally, building walls act as fire barriers. Accordingly, the service building is considered a nonsafety structure whose failure could affect a safety function.

The service building is part of a complex of interconnected buildings surrounding, but structurally independent of, the containment building. The walls between the service building and the other buildings, as well as the partitions in the building, are made of concrete blocks. The building has a combination of architectural brick siding and glass windows. The roofing, siding, and windows provide weather resistance and allow habitability control but are not designed to be resistant to wind or tornado missiles. During high wind or tornado events, the siding on the superstructure above elevation 271 feet would blow outward, thus relieving the pressure and wind loads. The components that might be affected by a tornado are the two CSTs. There is reasonable assurance that the feedwater supply will be maintained because of the available redundancy and because two-thirds of the tank volume is below grade. If the tanks are damaged, alternate protected feedwater sources are available.

The service building contains racks, panels, electrical enclosures, equipment supports and fire doors, penetration barriers, and seals. Those equipment sets receive a separate commodity group evaluation independent of the building evaluation. Building interior floor drains are evaluated with the treated water.

Table 2.4.2-9 of the LRA lists seven structural component groups requiring an AMR, provides a reference to the results of the AMR for each component group, and identifies the following intended functions for these structural component groups:

- structural support for nonsafety-related equipment
- shelter/protection of equipment
- fire barrier

2.4.2.9.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.9 and UFSAR Section 3.8.4 to determine whether there is reasonable assurance that the service building structural components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of its review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Table 2.4.2-9 of the LRA lists the following seven structural component groups that require an AMR:

(1) SB-ARCH-EXT (non-load-bearing building elements not relied upon in the safety analysis which provide normal habitability control and weather proofing (e.g., building siding, built up roof systems, windows, etc.))

(2) SB-BLOCK-INT (masonry block walls and mortar of the service building protected from the weather)

(3) SB-C-BUR (concrete in the service building that is in contact with the soil and ground water; embedded steel, reinforcement, and the embedded portion of anchor bolts; elastomer sealing material used below grade in the service building; post-construction urethane foam resin injected into seams and cracks to prevent ground-water intrusion)

(4) SB-C-EXT (concrete in the service building that is exposed to the weather; embedded steel, reinforcement, and the embedded portion of anchor bolts)

(5) SB-C-INT (concrete in the service building that is protected from the weather; embedded steel, reinforcement, and the embedded portion of anchor bolts; grout under column base plates)

(6) SB-FAST(CS)-INT (the exposed portion of carbon steel threaded fasteners in the service building that are protected from the weather)

(7) SB-SS(CS)-INT (structural carbon steel in the service building that is protected from the weather; columns, posts, beams, baseplates, bracing, crane support girders, crane rails, and the exposed faces of plates and structural members)

The staff has reviewed the information in LRA Section 2.4.2.9 and the UFSAR. The staff finds that the applicant made no omissions in scoping and screening the service building for license renewal.

2.4.2.9.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's response to the staff's RAI to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified the structural components of the service building that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified the structural components of the service building that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.10 Cable Tunnel

2.4.2.10.1 Summary of Technical Information in the Application

The applicant described the cable tunnel in LRA Section 2.4.2.10 and provided a list of components subject to an AMR in LRA Table 2.4.2-10.

The cable tunnel is a safety-related structure which houses and supports the electrical control circuits for most safety-related equipment. The cable tunnel includes a cofferdam, placed to protect the structure from the effects of external flooding. Accordingly, the cable tunnel contains NNS equipment whose failure could affect a safety function.

The cable tunnel is a below grade reinforced concrete structure supported by steel piles that has openings in the control building, the intermediate building, and the auxiliary building. The tunnel allows cables to be routed between these structures. The roof of the portion of the tunnel that extends to the control building is level with the yard grade. This section houses an escape hatch. The tunnel is protected from the effects of external flooding by a cofferdam surrounding the escape hatch. The cable tunnel is resistant to the effects of high winds and internally or externally generated missiles due to its underground configuration, the orientation of its openings, and the shielding provided by adjacent SCs.

The cable tunnel contains equipment supports and is also associated with fire penetration barriers and seals where it interfaces with the other structures. These equipment sets receive a separate commodity group evaluation independent of the structure evaluation. The structure interior floor drains are evaluated with the treated water system.

Table 2.4.2-10 of the LRA lists nine structural component groups requiring an AMR, provides a reference to the results of the AMR for each component group, and identifies the following intended functions for these structural component groups:

- structural support for safety-related equipment
- shelter/protection of equipment
- fire barrier

- pressure boundary
- flood barrier

2.4.2.10.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.10 to determine whether there is reasonable assurance that the cable tunnel structural components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of its review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Table 2.4.2-10 of the LRA lists the following nine structural component groups that require an AMR:

(1) PIPE (cable tunnel escape hatch gutter drain)

(2) TUNNEL-C-BUR (concrete in the cable tunnel that is in contact with the soil and ground water; embedded steel, reinforcement, and the embedded portion of anchor bolts; elastomer sealing material used below grade in the cable tunnel; post-construction urethane foam resin injected into seams and cracks to prevent ground water intrusion)

(3) TUNNEL-C-EXT (concrete in the cable tunnel that is exposed to the weather; embedded steel, reinforcement, and the embedded portion of anchor bolts)

(4) TUNNEL-C-INT (concrete in the cable tunnel that is protected from the weather; embedded steel, reinforcement, and the embedded portion of anchor bolts)

(5) TUNNEL-ELAST-EXT (elastomer sealing material in the cable tunnel that is exposed to the weather; elastomers are used between the escape hatch cofferdam and the exterior concrete)

(6) TUNNEL-FAST(CS)-EXT (the exposed portion of carbon steel threaded fasteners for the cable tunnel that are exposed to the weather)

(7) TUNNEL-SS(CS)-EXT (structural carbon steel for the cable tunnel (e.g., cofferdam) that is exposed to the weather)

(8) TUNNEL-SS(CS)-PILE (the carbon steel piles that comprise portions of the cable tunnel foundation)

(9) VALVE BODY (cable tunnel escape hatch gutter drain)

The staff has reviewed the information in LRA Section 2.4.2.10. The staff finds that the applicant made no omissions in scoping and screening the cable tunnel for license renewal.

2.4.2.10.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's response to the staff's RAI to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified the structural components of the cable tunnel that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified the structural components of the cable tunnel that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.11 Essential Yard Structures

2.4.2.11.1 Summary of Technical Information in the Application

The applicant described the essential yard structures in LRA Section 2.4.2.11 and provided a list of components subject to an AMR in LRA Table 2.4.2-11.

Within the site boundary there are structures and subterranean yard components that are necessary to support safety-related functions. These civil features emanate from design considerations that are typically independent of the function of the plant system associated with the feature. Accordingly, components evaluated within the essential yard structures group house and support, or provide shelter and protection, for safety-related or essential equipment.

The essential yard structures group is a listing of the major civil components found on site but not included within any other license renewal review boundary. (Note: Above- and below-grade tanks are evaluated with the mechanical system they serve, while the discharge canal is evaluated with the screenhouse.) The following SCs evaluated in this group:

- service water alternative discharge structure
- vital AC and DC duct banks, including their manholes and covers
- revetment armor stone
- transformer support pads

The primary service water discharge line discharges to the discharge canal and then to Lake Ontario. The redundant service water discharge line discharges to a Seismic Category I discharge structure, then to Deer Creek and to Lake Ontario. The redundant service water discharge line is normally in standby; however, it is occasionally placed in service for such activities as surveillance testing or maintenance work. Direct current control power from the station batteries is run in underground duct, separated, and apart from the cable tunnel, in order to maintain the necessary control in the event of an emergency. The electrical connections from the diesels to buses 17 and 18 are routed inside a separate underground duct bank from the diesel generator building to the screenhouse.

The breakwater that protects the plant from lake flooding is a stone revetment constructed in two reaches. The stone revetment was initially constructed with two layers of 5-ton minimum armor stones laid upon a 1.0 vertical to a 1.5 horizontal side slope to a minimum elevation of 257 feet mean sea level (msl). Because of the high lake levels that were predicted for Lake Ontario during the early 1970s, the crest elevation of the revetment was raised to a minimum of 261 feet msl by placement of cap stone along the top of the revetment.

Table 2.4.2-11 of the LRA lists five structural component groups requiring an AMR, provides a reference to the results of the AMR for each component group, and identifies the following intended functions for these structural component groups:

- cooling water source
- shelter/protection of equipment

2.4.2.11.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.11 to determine whether there is reasonable assurance that the essential yard structures components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of its review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Table 2.4.2-11 of the LRA lists the following five structural component groups that require an AMR:

(1) YARD-CASTIRON-EXT (cast iron for the essential yard structures (e.g., manhole covers) that are exposed to the weather)

(2) YARD-C-BUR (concrete in essential yard structures that is in contact with the soil and ground water; embedded steel, reinforcement, and the embedded portion of anchor bolts)

(3) YARD-C-EXT (concrete in the essential yard structures that is exposed to the weather; concrete used in the SW alternate discharge structure and the exposed portions of duct bank manholes; embedded steel, reinforcement, and the embedded portion of anchor bolts)

(4) YARD-C-INT (concrete in the essential yard structures that is protected from the weather; concrete used in the duct bank manholes; embedded steel, reinforcement, and the embedded portion of anchor bolts)

(5) YARD-STONE-EXT (armor stone used in the revetment)

Table 2.4.2-11 of the LRA states that the embedded portions of anchor bolts for three component groups (YARD-C-BUR, YARD-C-EXT, and YARD-C-INT) require an AMR. However, it does not address whether the exposed portions of anchor bolts require an AMR. In

RAI 2.4-1, the staff requested the applicant to explain whether the exposed portion of anchor bolts requires an AMR and, if it does not, provide a justification for the exclusion. The applicant responded to RAI 2.4-1 in the following:

> Table 2.4.2-11, Essential Yard Structures should contain an entry for Yard-Fast(CS)-EXT. The absence of this component asset was a typographical omission. This generic asset includes the exposed portion of carbon steel threaded fasteners for Yard Structures that are exposed to the weather. The intended functions for these assets include Structural Support NSR Equipment, Cooling Water Source and Shelter/Protect Equipment. The AMR for the generic asset is contained in Table 3.6-1 line number (16).

The staff has reviewed the information in LRA Section 2.4.2.11 and the additional information submitted by the applicant in response to the staff's RAI. The staff finds that the applicant made no omissions in scoping and screening the essential yard structures for license renewal.

2.4.2.11.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's response to the staff's RAI to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified the structural components of the essential yard structures that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified the structural components of the essential yard structures that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.12 Component Supports Commodity Group

2.4.2.12.1 Summary of Technical Information in the Application

The applicant described the component supports commodity group in LRA Section 2.4.2.12 and provided a list of components subject to an AMR in LRA Table 2.4.2-12.

System components physically interface with civil structures. The interface takes place in the form of component supports that position and bear the weight of the component assemblies and provide the proper amount of resistance to motion during normal operating conditions, accidents, transients, and off-normal events. Component supports are located throughout the plant. Included in the scope of the component support commodity group are supports for safety-related components and nonsafety-related components whose failure could affect a safety function (typically referred to as Seismic II/I).

The component support commodity group does not include evaluation of snubbers (considered active per NEI 95-10) or the reactor vessel, RCPs, SGs, pressurizer, and other RCS supports, all of which receive a separate evaluation.

The component support commodity group includes those structural elements that are connected to civil structures and which extend to a system or system components for the purpose of providing support or restraint. Included in this boundary definition are any vibration dampeners or other passive connective appurtenances intrinsic to the functioning of the support. The commodity group also includes spray or drip shields attached to equipment and electrical system rack, panels, and enclosures. For mechanical systems, the evaluation boundary includes the connections to or around piping systems, bracing and framing for tanks, pumps and skids, etc.

Component supports provide the connection between a system's equipment or component and a plant structural member (e.g., wall, floor, ceiling, column, beams, etc.). They provide support for distributed loads (e.g., piping, tubing, HVAC ducting,) and localized loads (e.g., individual equipment). Pipe restraints, consisting of failure restraints and seismic restraints, limit pipe movement during postulated events. For electrical systems, the evaluation boundary includes the connections to raceways, cable trays, and conduits. The evaluation boundary also includes the raceways, cable trays, and conduits, as well as racks, panels, or enclosures which house or support system components within the scope of license renewal. Raceways and cable trays identify a general component type that is designed specifically for holding electrical wires and cables. Like mechanical system supports, electrical supports provide support for distributed loads (e.g., cable trays, raceways, conduit) and localized loads (e.g., individual equipment, cabinets, junction boxes, etc.).

Only seismically analyzed supports for system piping greater than or equal to 4 inches are uniquely field labeled and tracked in the plant database. These supports do not include all of the supports that are in the scope of license renewal. Because of the difficulty in uniquely distinguishing supports, all supports for safety-related equipment and all supports for any equipment contained within a safety-related structure, regardless of the equipment's seismic classification, shall be considered within the scope of license renewal unless a support is specifically excepted and that exception documented. Additionally, other structures also house and support equipment that is in the scope of the Rule. Component supports for those equipment sets are also in the scope of license renewal.

Table 2.4.2-12 of the LRA lists 20 structural component groups requiring an AMR, provides a reference to the results of the AMR for each component group, and identifies the following intended functions for these structural component groups:

- structural support for nonsafety-related equipment
- structural support for safety-related equipment

2.4.2.12.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.12 to determine whether there is reasonable assurance that the component supports commodity group components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Table 2.4.2-12 of the LRA lists the following 20 structural component groups that require an AMR:

(1) CSUPP-AL-INT (aluminum alloy electrical conduit and conduit supports that are not exposed to the weather)

(2) CSUPP-ASME(CS)-EXT (structural carbon steel used in nuclear steam supply system (NSSS) pipe and component supports that is outdoors (i.e., exposed to the weather))

(3) CSUPP-ASME(CS)-INT (structural carbon steel used in NSSS pipe and component supports that is indoors (i.e., protected from the weather))

(4) CSUPP-ELAST-INT (elastomer (e.g., vibration isolator equipment mounts) that is protected from the weather; cabinet door seals, gaskets, and other seals)

(5) CSUPP-EXP(CS)-EXT (carbon steel expansion/grouted anchors that are exposed to the weather)

(6) CSUPP-EXP(CS)-INT (carbon steel expansion/grouted anchors that are not exposed to the weather)

(7) CSUPP-EXP(SS)-RW (stainless steel expansion/grouted anchors that are submerged in raw water)

(8) CSUPP-FAST(CS)-EXT (carbon steel structural fasteners (e.g., bolts, studs, nuts) that are exposed to the weather)

(9) CSUPP-FAST(CS)-INT (carbon steel structural fasteners (e.g., bolts, studs, nuts) that are protected from the weather; indoor air is considered to be non-air-conditioned (bounding condition), even though some fasteners are within boundaries for air conditioned areas (e.g., control building))

(10) CSUPP-FAST(HSLAS)-INT (High strength carbon steel structural fasteners (e.g., bolts, studs, nuts), whose yield strength is greater than 150 ksi, that are protected from the weather, used for selected electrical enclosures and a limited number of structural steel component supports)

(11) CSUPP-FAST(SS)-RW (stainless steel fasteners (e.g., bolts, studs, nuts, etc.) that are submerged in raw water)

(12) CSUPP-G-INT (grout used in expansion/grouted anchors within the plant; expansion/ grouted anchors include Hilti bolts but do not include Drillco Maxi-Bolts; grout used as a component support under equipment bases; grout used as a fire barrier is evaluated as a separate commodity group)

(13) CSUPP-SS(CS)-EXT (structural carbon steel (e.g., plates, channels, support members) that is exposed to the weather)

(14) CSUPP-SS(CS)-INT (structural carbon steel (e.g., plates, beams, support members) that is indoor (i.e., protected from the weather); indoor air is considered to be non-air-conditioned (bounding condition), even though some steel surfaces are within boundaries for air conditioned areas (e.g., control building); electrical enclosure drip guards and spray shields)

(15) CSUPP-SS(SS)-RW (structural stainless steel (e.g., plates, beams, support members) that is submerged in raw water)

(16) CSUPP-SURFACE-ELAST-EXT (nonmetallic materials used in NSSS pipe and component supports that are exposed to the weather)

(17) CSUPP-SURFACE-ELAST-INT (nonmetallic materials used in NSSS pipe and component supports that are protected from the weather)

(18) CSUPP-SURFACE-METAL-EXT (metallic surfaces used in NSSS pipe and component supports that are exposed to the weather)

(19) CSUPP-SURFACE-METAL-INT (metallic surfaces used in NSSS pipe and component supports that are protected from the weather)

(20) CSUPP-WOOD-INT (wood used in electrical cable support spacers and the intermediate building supply fan support frame)

Table 2.4.2-12 of the LRA indicates that the grout used for Hilti bolts requires an AMR, but the grout used for Drillco Maxi-Bolts is excluded from an AMR. In RAI 2.4-3, the staff asked the applicant to provide a justification for the exclusion of the grout used for Drillco Maxi-Bolts. In response to RAI 2.4-3, the applicant stated the following:

> All grout associated with supporting components that are within the scope of the rule, together with the grout in which Drillco Maxi-Bolts are embedded, is included for AMR. The language used in Table 2.3.2-12 was meant to distinguish that Drillco Max-Bolts have a design installation technique different from other types of embedded anchor bolt configurations. That difference typically results in bolt shaft failure rather than grout failures when the component is over stressed.

In RAI 2.4-5, the staff states that the intake structure, intake canal, cable trays and supports, tube track, reactor vessel internals, pipe hangers, and supports have been listed as items requiring an AMR for other plants submitting an LRA. The staff did not find these structures or structural components listed in the Ginna LRA as requiring an AMR. The staff asked the applicant to explain whether these structures or structural components require an AMR, and, if they do not, to justify their exclusion. In response to RAI 2.4-5, the applicant stated the following:

> The intake structure and tunnel are not within the scope of license renewal. This is explained in Section 2.4.2.7 of the LRA. The Screen House and discharge canal have features which provide water intake from the discharge canal to the Service Water system should the Circulating Water intake tunnel become unavailable. The cable trays and supports are included in LRA section 2.4.2-12, and tube track in LRA Table 2.4.1-1 under component group CV-SS(SS)-INT. The reactor vessel internals are included in LRA 2.3.1.3. Pipe hangers and supports are included in LRA section 2.4.2-12.

The staff has reviewed the information in LRA Section 2.4.2.12, and the additional information submitted by the applicant in response to the staff's RAIs. The staff finds that the applicant made no omissions in scoping and screening the component supports commodity group for license renewal.

2.4.2.12.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's responses to the staff's RAIs to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified the structural components of the component supports commodity group that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified the structural components of the component supports commodity group that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.3 Nonessential Buildings and Yard Structures

2.4.3.1 Summary of Technical Information in the Application

The applicant described the nonessential buildings and yard structures in LRA Section 2.4.3 and stated that these buildings and structures are not within the scope of license renewal because they do not serve an intended function.

The nonessential buildings, structures, and yard components group is a listing of the major civil components found on site but not included within any other license renewal review boundary. (Note: Above- and below-grade tanks are evaluated with the mechanical system they serve. Some external tanks have dikes and spill abatement features included in this list.) A review of the UFSAR and other CLB documents, as well as field verifications, was performed to ensure that these civil features do not meet the criteria to be considered in the scope to license renewal. Structures and components evaluated in this group include the following:

- nuclear engineering services building located on the northwest side of site boundary, used for office space (also contains the emergency plan engineering support facility)

- miscellaneous storage building located east of engineering building, used for equipment and spare parts storage

- office trailers at various locations around the site, used for office space and storage

- steam generator facilities building located northeast of plant, used as office space (previously used for steam generator repair training)

- radwaste storage building located northeast of plant, used for contaminated waste storage

- sodium hypochlorite tank with spill containment dike located north of plant and east of screenhouse, used for chemical storage for secondary water treatment

- ammonia storage tank with spill containment dike located north of plant and south of screenhouse, used for chemical storage for secondary water treatment

- roadways, paths, and sidewalks located around the site, used for personnel and equipment access/egress

- contaminated storage building located south of auxiliary building, used for personnel and equipment access/egress

- guardhouse located on the south side of site boundary, centerline, used for personnel access/egress

- warehouse/construction office (Butler building) located west of plant, used for office space, the wellness center, and the machine shop

- miscellaneous storage building located south of engineering building, used for equipment and spare parts storage

- off-load portal located west of guardhouse on the south site boundary, used as a shipping transfer point from offsite warehouse into the secure area

- hydrogen building located south of auxiliary building contains hydrogen and nitrogen bottled gas for the volume control tank

- high mast lighting located throughout the site, used for security lighting

- security fences and structures at various locations around the site perimeter, used for site access control

- various storm drainage structures located throughout the site, used for ground water runoff control

- lube oil storage building located north of turbine building, used for oil storage

- hydrogen bottle house located north of turbine building contains hydrogen and carbon dioxide bottled gas, used for the main electrical generator

- high integrity container storage facility located west of the radwaste storage building, used for shielding for containerized spent resin prior to shipment

- old steam generator storage facility located northwest of the plant outside the security fence, used to house the old steam generators and designed for long-term storage

2.4.3.2 Staff Evaluation

The staff reviewed LRA Section 2.4.3 to determine whether there is reasonable assurance that the nonessential buildings and yard structures components that are within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of its review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Based on its review of the LRA, the staff finds that the applicant has made adequate decisions that these nonessential buildings and yard structures components should not be in scope and subject to an AMR because they do not perform license renewal intended functions.

2.4.3.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's response to the staff's RAI to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified the structural components of the nonessential buildings and yard structures that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified the structural components of the nonessential buildings and yard structures that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.4 Evaluation Findings

On the basis of this review, the staff concludes that there is reasonable assurance that the applicant has adequately identified the structures and structural components that are within the scope of license renewal, in accordance with the requirements of 10 CFR 54.4(a), and that the applicant has adequately identified the structural components that are subject to an AMR, in accordance with the requirements of 10 CFR 54.21(a)(1).

2.5 Scoping and Screening Results: Electrical and Instrumentation and Controls Systems

This section addresses the electrical systems' scoping and screening results for license renewal. The applicant has chosen to evaluate the electrical and I&C components on a plant-wide basis (rather than on a system basis) as commodities utilizing the "spaces" approach and the "bounding review technique." The Ginna LRA identifies the following list of generic electrical and I&C commodity groups (the SER sections which evaluate the commodity groups are also provided) that are addressed in LRA Section 2.5:

- Medium-Voltage Insulated Cables and Connections (2.5.1.1)
- Low-Voltage Insulated Cables and Connections (2.5.1.2)
- Electrical Portions of Electrical and I&C Penetration Assemblies (2.5.1.3)
- Electrical Phase Bus (2.5.1.4)
- Switchyard Bus (2.5.1.5)
- Transmission Conductors (2.5.1.6)
- Uninsulated Ground Conductors (2.5.1.7)
- High-Voltage Insulators (2.5.1.8)

Pursuant to 10 CFR 54.21(a)(1), an applicant must identify and list SCs subject to an AMR. These are passive, long-lived SCs that are within the scope of license renewal. To verify that the applicant has properly implemented its methodology, the staff focuses its review on the implementation results. Such a focus allows the staff to confirm that there is no omission of electrical system components that are subject to an AMR. If the review identifies no omission, the staff has the basis to find that there is reasonable assurance that the applicant has identified the electrical system components that are subject to an AMR.

2.5.1 Commodity Group Discussion

Section 2.1.7.4 of the LRA states that by using this methodology, initially all passive long-lived electrical and I&C commodity groups are considered subject to an AMR. The plant is segregated into areas where common, bounding environmental parameters can be assigned; an AMR is performed on the most limiting commodity in that area. If the AMR finds that aging management activities are required, Section 2.1.7.4 indicates that "component specific scoping" may be performed on the components in those commodity groups. This is done to limit the number of components for which aging management activities are required, or to eliminate the aging management activity altogether if no components remain in the material/environment group population following the scoping. The staff asked the applicant to identify the components that were eliminated from aging management activities through component specific scoping and to provide the justification for doing so. The applicant provided a list of these components in a letter dated May 23, 2003. These components are identified and evaluated in the staff's evaluation of the generic commodity groups in which they are a member.

The generic electrical and I&C commodity groups identified by the applicant are addressed in the following sections.

2.5.1.1 Medium-Voltage Insulated Cables and Connectors

2.5.1.1.1 Summary of Technical Information in the Application

The applicant described the medium voltage insulated cable and connection commodity group in LRA Section 2.5.1. Tables 2.5.4-1, 2.5.6-1, and 2.5.8-1 identify the systems which contain this commodity group, as well as the passive function and aging management references for the commodity group.

An insulated cable is an assembly of a single electrical conductor (wire) with an insulation covering or a combination of conductors insulated from one another. Medium voltage cables operate between 1,000 V and 15,000 V and are normally shielded. Power cables at Ginna Station operate at a nominal voltage of 4160 V. Connections (or terminations) are used to connect the cable conductors to other cables or electrical devices. Connections include, but are not limited to, mechanical connections, splices, terminal blocks, and fuse holders not included within other assemblies. The license renewal function of these components is to provide electrical connections to specified sections of an electrical circuit to deliver voltage, current, or signals.

2.5.1.1.2 Staff Evaluation

The staff reviewed LRA Sections 2.5.1 and 2.5.2, UFSAR Sections 8.1, 8.2, and 8.3, and the applicant's responses to the staff's RAIs. The purpose of the review was to determine whether there is reasonable assurance that the medium-voltage insulated cables and connections within the scope of license renewal and subject to an AMR had been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected the nonessential buildings/areas identified in LRA Section 2.4.3 to verify that medium-voltage insulated cables and connections having intended functions that might be located in those spaces were not omitted from the scope of the Rule. This is consistent with the treatment of the medium-voltage insulated cables and connections as a commodity utilizing the "plant spaces" approach. The staff focused on medium voltage cables and connections that were not identified as being subject to an AMR to determine if any medium-voltage cables and connections were omitted.

In a conference call with the applicant on January 15, 2003, the applicant stated that electrical and I&C components located within the plant spaces identified in LRA Section 2.4.3 do not perform any license renewal intended functions and, therefore, are not included within the scope of license renewal. The staff reviewed the plant spaces (buildings/areas) identified in LRA Section 2.4.3 against information contained in the Ginna UFSAR. The staff did not find any indication in the UFSAR that these spaces contain electrical or I&C components (including medium voltage insulated cables and connections) that perform a license renewal intended function. In addition, inspectors toured selected SCs listed in Section 2.4.3 of the LRA, including items (a), (b), (d), (f), (n), (s), and (t), and determined that there were no electrical components in them. Buildings (u) and (e) could not be entered because they were sealed with the radioactive components (see AMP audit report dated September 8, 2003).

With regard to plant spaces that do include electrical and I&C components that perform a license renewal intended function, LRA Section 2.1.7.4 indicates that component specific scoping may have been performed in those spaces. This was done to limit the number of components for which aging management activities are required, or to eliminate aging management activities altogether if nothing remains in that particular material/environment group population. An example of this is found in LRA Section 3.7, under the heading Environment, which states that Ginna has four medium-voltage power cables installed in underground duct banks. It was determined that a failure of these cables would not prevent the satisfactory accomplishment of any intended function. The LRA states that, therefore, a further review of this environment was not required. The staff asked the applicant whether there are any other underground circuits in the 2 kV or higher voltage range (including 34.5 kV circuits). If so, the applicant was asked to include them in the response to the following request.

The staff asked the applicant to identify each of the electrical and I&C components (including medium voltage insulated cables and connections) that were eliminated from aging management activities through component specific scoping, and to identify the plant SSCs that are served by those components. The applicant was also asked to provide the basis used in each case for concluding that those SSCs do not provide any license renewal intended functions identified in 10 CFR 54.4(a). The response to the staff’s request was provided by the applicant in a letter dated May 23, 2003.

With regard to the staff’s question on 34.5 kV underground circuits, the applicant stated that Ginna is supplied by the offsite power system via two 34.5 kV circuits. This is consistent with interim staff guidance on SBO because the evaluation boundary for the offsite power system starts at the 34.5 kV circuit breakers upstream of the startup transformers. The applicant therefore states that the 34.5 kV cables feeding these breakers are outside of the evaluation boundary and were not evaluated as part of license renewal. The staff agrees that the 34.5 kV circuits feeding the circuit breakers are outside of the evaluation boundary. The staff’s evaluation of the SBO evaluation boundary used by the applicant is contained in Section 2.5.1.5.2 of this SER.

The applicant’s May 23, 2003, responses also identified the medium voltage cables that were eliminated from aging management activities through component specific scoping. The following cables were identified and justification for their elimination was provided:

- Cable M0010 provides the normal 4 kV source of power to circulating water pump A. A credible failure of this cable will result in a loss of power to the circulating water pump. Circulating water pump A does not perform an intended function. With regard to interim staff guidance on SBO, this cable is not required to recover from an SBO event.

- Cable M0170 provides the normal 4 kV source of power to circulating water pump B. A credible failure of this cable will result in a loss of power to the circulating water pump. Circulating water pump B does not perform an intended function. With regard to interim staff guidance on SBO, this cable is not required to recover from an SBO event.

- Cable M0089 provides the normal 4 kV source of power to station service transformer 18. This transformer is one of two sources of 480 V power for bus 18. A credible failure of this cable does not result in a loss of an intended function. With regard to interim staff guidance on SBO, this cable is not required to recover from an SBO event.

- Cable M0108 provides the normal 4 kV source of power to station service transformer 17. This transformer is one of two sources of 480 V power for bus 17. A credible failure of this cable does not result in a loss of an intended function. With regard to interim staff guidance on SBO, this cable is not required to recover from an SBO event.

The staff agrees that cables M0010 and M0170 do not provide a license renewal function. The staff, however, questioned the elimination of cables M0089 and M0108 from the license renewal scope. These circuits are part of the offsite power path that brings offsite power into safety buses 17 and 18 serving the SW pumps. The staff therefore asked the applicant to clarify how the Ginna plant can be brought to a shutdown condition from the offsite power supply if these circuits to the safety-related shutdown buses are not included within the scope of license renewal.

In a July 11, 2003, response to staff clarification questions, the applicant stated that circuits M0089 and M0108 are not relied upon to cope with, or recover from, an SBO. The entry conditions for plant procedure ECA-0.0, “Loss of All AC Power,” is the loss of bus 14 and bus 16. This procedure is not entered when bus 17 and bus 18 are lost. Upon restoration of bus 14 and/or bus 16, recovery actions are taken. These recovery actions do not rely upon bus 17 or bus 18, although they may be used if available. This procedure directs activities required to achieve shutdown conditions.

The response to the staff’s question does not indicate how long Ginna can remain in a safe condition following recovery of only safety buses 14 and 16. The Ginna UFSAR (Section 8.3.1.1.6) indicates that buses 17 and 18, which are powered from the cables in question (M0089 and M0108), supply power to the Ginna SW pumps. The concern is that recovery of offsite power to only buses 14 and 16 following an SBO will only allow the plant to continue to operate in the hot standby or hot shutdown condition. While hot standby or hot shutdown is acceptable for plant operation during the SBO coping period, if Ginna cannot be brought to cold shutdown, recovery of buses 14 and 16 may result in only a few additional hours beyond Ginna’s required 4-hour coping capability. Unavailability of condensate feedwater or other limitations could limit operation in these modes. The staff notes that recovery of the Ginna

EDGs following an SBO would allow energization of the full complement of safety buses, including buses 17 and 18. Hot standby or hot shutdown has been accepted by the staff at some plants for non-SBO scenarios, such as fire protection; however, it is not clear that the same limitations as those following an SBO event exist for the other scenarios. The applicant should identify the length of time Ginna can remain in a safe condition following recovery of only safety buses 14 and 16 and provide the justification for the acceptability of that time. The justification could refer to the staff's acceptance of comparable times for other scenarios at Ginna, evidence of the ability to repair a Ginna EDG in that time period, or comparability of that time to other staff-accepted time periods (e.g., required fuel oil supplies for the Ginna EDGs). This was Open Item 2.5-1.

In a letter dated December 9, 2003, the applicant provided a reply to Open Item 2.5-1. The reply states—

> RG&E has determined that cables M0089 and M0108 will be placed within the scope of license renewal, and subject to aging management review. A description of the new aging management program, which is consistent with NUREG-1801, XI.E3, to address these cables is provided in Attachment 2 - "Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements".

The staff reviewed the 10 elements of the new AMP provided in Attachment 2 to the December 9, 2003, letter (reference section 3.6.2.3.4 of this SER). The AMP calls for testing of the cables at least once every 10 years, with the first test to be completed before the period of extended operation. The staff agrees with the applicant that the new AMP is consistent with NUREG-1801 (GALL) Program XI.E3, and is therefore acceptable. This resolves Open Item 2.5-1.

2.5.1.1.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's responses to the staff's RAI to determine whether any electrical and I&C commodity groups that should be within the scope of license renewal were not identified by the applicant. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. On the basis of this review, the staff concludes that the applicant has appropriately identified the medium-voltage insulated cables and connections that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified the medium-voltage insulated cables and connections that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.5.1.2 Low-Voltage Insulated Cables and Connectors

2.5.1.2.1 Summary of Technical Information in the Application

The applicant described the low-voltage insulated cables and connections commodity group in LRA Section 2.5.1. Tables 2.5.2-1, 2.5.3-1, 2.5.4-1, 2.5.5-1, 2.5.6-1, 2.5.7-1, 2.5.8-1, 2.5.9-1, 2.5.10-1, 2.5.11-1, 2.5.12-1, 2.5.13-1, and 2.5.14-1 identify the systems that contain this commodity group, as well as the passive function and aging management references for the commodity group.

An insulated cable is an assembly of a single electrical conductor (wire) with an insulation covering or a combination of conductors insulated from one another. Low-voltage cables operate at voltage levels below 600 volts alternating current. This includes power, instrumentation, control, and communications cables. Connections (or terminations) are used to connect the cable conductors to other cables or electrical devices. Connections include, but are not limited to, mechanical connections, splices, terminal blocks, and fuse holders not included within other assemblies. The license renewal intended function of these components is to provide electrical connections to specified sections of an electrical circuit to deliver voltage, current, or signals.

2.5.1.2.2 Staff Evaluation

The staff reviewed LRA Sections 2.5.1 and 2.4.3, UFSAR Sections 8.1, 8.2, and 8.3, and the applicant's responses to the staff's RAIs. The purpose of the review was to determine whether there is reasonable assurance that the low-voltage insulated cables and connections within the scope of license renewal and subject to an AMR had been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected the nonessential buildings/areas identified in LRA Section 2.4.3 to verify that low-voltage insulated cables and connections having intended functions that might be located in those spaces were not omitted from the scope of the Rule. This is consistent with the treatment of the low voltage insulated cables and connections as a commodity utilizing the "plant spaces" approach. The staff focused on low voltage insulated cables and connections that were not identified as being subject to an AMR to determine if any low-voltage insulated cables and connections were omitted.

In a conference call with the applicant on January 15, 2003, the applicant stated that electrical and I&C components located within the plant spaces identified in LRA Section 2.4.3 do not perform any license renewal intended functions and, therefore, are not included within the scope of license renewal. The staff reviewed the plant spaces (buildings/areas) identified in LRA Section 2.4.3 against information contained in the Ginna UFSAR. The staff did not find any indication in the UFSAR that these spaces contain electrical or I&C components (including low-voltage insulated cables and connections) that perform a license renewal intended function. In addition, selected buildings/areas identified in LRA Section 2.4.3 were audited during the NRC license renewal inspections. The inspector toured selected SCs listed in Section 2.4.3 of the LRA, including Items (a), (b), (d), (f), (n), (s), and (t), and determined that there were no electrical components in them. Buildings (u) and (e) could not be entered into because they are sealed with the radioactive components.

With regard to plant spaces that do include electrical and I&C components that perform a license renewal intended function, LRA Section 2.1.7.4 indicates that component specific scoping may be performed in those spaces. This is done to limit the number of components for which aging management activities are required, or to eliminate aging management activities altogether if nothing remains in that particular material/environment group population.

The staff asked the applicant to identify each of the electrical and I&C components (including low-voltage insulated cables and connections) that were eliminated from aging management activities through component specific scoping, and to identify the plant SSCs that are served by those components. The applicant was also asked to provide the basis used in each case for concluding that those SSCs do not provide any license renewal intended functions identified in 10 CFR 54.4(a). The response to the staff's request was provided by the applicant in a letter dated May 23, 2003. There were no components identified by the applicant in the low-voltage insulated cables and connections category that were eliminated from aging management activities through component specific scoping.

2.5.1.2.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's response to the staff's RAI to determine whether any electrical and I&C commodity groups that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified the low-voltage insulated cables and connections that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified the low-voltage insulated cables and connections that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.5.1.3 Electrical Penetration Assemblies

2.5.1.3.1 Summary of Technical Information in the Application

The applicant described the electrical penetration assemblies commodity group in LRA Section 2.5.1.

Electrical penetration assemblies consist of one or more electrical conductors and a pressure boundary between the inboard and outboard sides of the penetration capable of maintaining electrical continuity through the boundary. These penetrations are used to transmit electrical power and signals through the containment wall. The license renewal intended function of these components is to provide electrical connections to specified sections of an electrical circuit to deliver voltage, current, or signals. The review of the electrical penetration assemblies did not include the pressure boundary function, which is discussed in the containment structural review. All primary containment electrical penetration assemblies at Ginna Station are included in the scope of the Environmental Qualification Program in accordance with 10 CFR 50.49. The TLAA of electrical penetration assemblies is described in Section 4.4.3 of the LRA.

2.5.1.3.2 Staff Evaluation

Section 2.5.1 of the LRA states that all primary containment electrical penetration assemblies at Ginna Station are included in the scope of the Environmental Qualification Program (10 CFR 50.49). Components that are covered under this program are evaluated in Section 4.4 of this SER.

2.5.1.4 Electrical Phase Bus

2.5.1.4.1 Summary of Technical Information in the Application

The applicant described the electrical phase bus commodity group in LRA Section 2.5.1. Tables 2.5.4-1 and 2.5.5-1 identify the systems which contain this commodity group, as well as the passive function and aging management references for the commodity group.

Phase buses consist of rigid electrical conductors that are enclosed within their own enclosure or vault and are not part of an active component, such as a switchgear, load center, or motor control center. Phase buses are discussed as three distinct types—isolated phase bus, nonsegregated phase bus, and segregated phase bus. Only the nonsegregated phase bus is within the scope of license renewal at Ginna Station. This includes the 480 V diesel generator bus and the portions of the 4.16 kV bus that provide a normal source of power for the 480 V Class 1E power system. The license renewal intended function of these components is to provide electrical connections to specified sections of an electrical circuit to deliver voltage, current, or signals.

2.5.1.4.2 Staff Evaluation

The staff reviewed LRA Sections 2.5.1 and 2.4.3, UFSAR Sections 8.1, 8.2, and 8.3, and the applicant's responses to the staff's RAIs. The purpose of the review was to determine whether there is reasonable assurance that the electrical phase buses within the scope of license renewal and subject to an AMR had been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected the nonessential buildings/areas identified in LRA Section 2.4.3 to verify that the electrical phase buses having intended functions that might be located in those spaces were not omitted from the scope of the Rule. This is consistent with the treatment of the electrical phase bus as a commodity utilizing the "plant spaces" approach. The staff focused on the electrical phase buses that were not identified as being subject to an AMR to determine if any electrical phase bus was omitted.

In a conference call with the applicant on January 15, 2003, the applicant stated that electrical and I&C components located within the plant spaces identified in LRA Section 2.4.3 do not perform any license renewal intended functions and, therefore, are not included within the scope of license renewal. The staff reviewed the plant spaces (buildings/areas) identified in LRA Section 2.4.3 against information contained in the Ginna UFSAR. The staff did not find any indication in the UFSAR that these spaces contain electrical or I&C components (including electrical phase buses) that perform a license renewal intended function. In addition, selected buildings/areas identified in LRA Section 2.4.3 were audited during the NRC license renewal inspections. The inspector toured selected SCs listed in Section 2.4.3 of the LRA, including Items (a), (b), (d), (f), (n), (s), and (t), and determined that there were no electrical components in them. Buildings (u) and (e) could not be entered because they were sealed with the radioactive components.

With regard to plant spaces that do include electrical and I&C components that perform a license renewal intended function, LRA Section 2.1.7.4 indicates that component specific scoping may be performed in those spaces. This is done to limit the number of components for which aging management activities are required, or to eliminate aging management activities altogether if nothing remains in that particular material/environment group population.

The staff asked the applicant to identify each of the electrical and I&C components (including electrical phase buses) that were eliminated from aging management activities through component specific scoping, and to identify the plant systems, SSCs that are served by those components. The applicant was also asked to provide the basis used in each case for concluding that those SSCs do not provide any license renewal intended functions identified in 10 CFR 54.4(a). The response to the staff's request was provided by the applicant in a letter dated May 23, 2003. The responses identified the electrical phase buses that were eliminated from aging management activities through component specific scoping. The following electrical phase buses and the justification for their elimination was provided:

- 19 kV iso-phase bus provides power from the main generator to the station unit transformer and the main transformer (generator step-up transformer). A credible failure of this phase bus results in a loss of power generation. With regard to interim staff guidance on SBO, this phase bus is not required to recover from an SBO event.

- 11A/11B phase bus provides power from the station unit transformer to 4 kV buses 11A and 11B. A credible failure of this phase bus results in a loss of power generation. With regard to interim staff guidance on SBO, this phase bus is not required to recover from an SBO event.

- Control rod drive bus provides power from the motor-generator sets to the reactor trip breakers and the rod drive power distribution system. A credible failure of this bus results in a loss of power to the control rod drive mechanisms and a rod insertion. With regard to interim staff guidance on SBO, this phase bus is not required to recover from an SBO event.

The staff agrees that the above listed electrical phase buses do not provide a license renewal function.

2.5.1.4.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's response to the staff's RAI to determine whether any electrical and I&C commodity groups that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified the electrical phase buses that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified the electrical phase buses that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.5.1.5 Switchyard Bus

2.5.1.5.1 Summary of Technical Information in the Application

The applicant described the switchyard bus commodity group in LRA Section 2.5.1. Table 2.5.8-1 identifies the system which contains this commodity group, as well as the passive function and aging management references for the commodity group.

The switchyard bus is an uninsulated, unenclosed, rigid electrical conductor used in switchyards and switching stations to connect two or more elements of an electrical power circuit, such as disconnect switches and transmission conductors. The switchyard bus at Ginna Station is used to distribute 34.5 kV power from the offsite power circuits (751 and 767) to the oil circuit breakers and then to the station auxiliary transformers. The license renewal intended function of these components is to provide electrical connections to specified sections of an electrical circuit to deliver voltage, current, or signals.

2.5.1.5.2 Staff Evaluation

The staff reviewed LRA Sections 2.5.1 and 2.4.3, UFSAR Sections 8.1, 8.2, and 8.3, and the applicant's responses to the staff's RAIs. The purpose of the review was to determine whether there is reasonable assurance that the switchyard buses within the scope of license renewal and subject to an AMR had been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

In the performance of the review, the staff selected the nonessential buildings/areas identified in LRA Section 2.4.3 to verify that the switchyard buses having intended functions that might be located in those spaces were not omitted from the scope of the Rule. This is consistent with the treatment of the switchyard bus as a commodity utilizing the "plant spaces" approach. The staff focused on the switchyard buses that were not identified as being subject to an AMR to determine if any switchyard buses were omitted.

In a conference call with the applicant on January 15, 2003, the applicant stated that electrical and I&C components located within the plant spaces identified in LRA Section 2.4.3 do not perform any license renewal intended functions and, therefore, are not included within the scope of license renewal. The staff reviewed the plant spaces (buildings/areas) identified in LRA Section 2.4.3 against information contained in the Ginna UFSAR. The staff did not find any indication in the UFSAR that these spaces contain electrical or I&C components (including switchyard buses) that perform a license renewal intended function. In addition, selected buildings/areas identified in LRA Section 2.4.3 were audited during the NRC license renewal inspections. The inspector toured selected SCs listed in Section 2.4.3 of the LRA, including Items (a), (b), (d), (f), (n), (s), and (t), and determined that there were no electrical components in them. Buildings (u) and (e) could not be entered because they were sealed with the radioactive components.

With regard to plant spaces that do include electrical and I&C components that perform a license renewal intended function, LRA Section 2.1.7.4 indicates that component specific scoping may be performed in those spaces. This is done to limit the number of components for which aging management activities are required, or to eliminate aging management activities altogether if nothing remains in that particular material/environment group population.

The staff asked the applicant to identify each of the electrical and I&C components (including switchyard buses) that were eliminated from aging management activities through component specific scoping; and to identify the plant SSCs that are served by those components. The applicant was also asked to provide the basis used in each case for concluding that those SSCs do not provide any license renewal intended functions identified in 10 CFR 54.4(a). The response to the staff's request was provided by the applicant in a letter dated May 23, 2003. The response identified the switchyard bus that was eliminated from aging management activities through component specific scoping. The following switchyard bus was identified and the justification for its elimination was provided:

- 115 kV switchyard bus provides a connection between the generator step-up transformer and the offsite power distribution system. A credible failure of this bus results in a loss of power generation, which is not required to perform an intended function. With regard to interim staff guidance on SBO, this switchyard bus is not required to recover from an SBO event.

The staff agrees that this switchyard bus does not serve a license renewal required function.

Switchyard buses are often used in the offsite power circuits that are required to be included within the scope of license renewal, consistent with the requirements in 10 CFR 54.4(a)(3) relative to SBO. With regard to the offsite power circuits, Section 2.5.8 of the LRA indicates that the 115 kV switchyard (Station 13A) is not included within the scope of license renewal. The information in the application also indicates that the 34.5 kV switchyard (Station 204) is not included within the scope of license renewal. In the Ginna design, there are two 34.5 kV circuit breakers shown in UFSAR Figure 8.1-1—upstream of station auxiliary (startup) transformers 12A and 12B and between the transformers and their respective switchyards (Stations 204 and 13A).

The staff guidance, "Scoping of Equipment Relied On to Meet the Requirements of the SBO Rule (10 CFR 50.63) for License Renewal (10 CFR 54.4(a)(3))," was provided to the Nuclear Energy Institute and the Union of Concerned Scientists in a letter dated April 1, 2002. The guidance states that—

> For purposes of the license renewal rule, the staff has determined that the plant system portion of the offsite power system that is used to connect the plant to the offsite power source should be included within the scope of the rule. This path typically includes the switchyard circuit breakers that connect to the offsite system power transformers (startup transformers), the transformers themselves, the intervening overhead or underground circuits between circuit breaker and transformer and transformer and the onsite electrical distribution system, and the associated control circuits and structures.

The Ginna offsite power system design is not configured like the typical design described in the guidance. It has the intervening 34.5 kV circuit breakers between the switchyard circuit breakers and the startup (station auxiliary) transformers. In order for the staff to determine whether the plant system portion of the offsite power system should end with the 34.5 kV circuit breakers or with the upstream switchyard circuit breakers at Stations 13A and 204, the staff needed to determine which circuit breakers provided the bulk of the plant system electrical services (e.g., providing plant power, protecting downstream circuits, and providing plant operator-controlled isolation and energization capability). Both groups of circuit breakers clearly provide power to the plant. The applicant was asked to indicate which group of breakers are tripped upon actuation of the electrical protective features for the station auxiliary transformers and downstream circuits, and which group can be tripped open or closed by the Ginna plant operator.

If the bulk of the plant system electrical services were provided by the switchyard circuit breakers and not the 34.5 kV breakers, the applicant was asked to provide the basis for concluding that the plant system portion of the offsite power system ends with the 34.5 kV circuit breakers rather than the switchyard circuit breakers.

The applicant provided the following response in its May 23, 2003, letter:

> Circuit breakers 52/76702 and 52/75112 are located in the onsite transformer yard. These circuit breakers are tripped upon actuation of the electrical protective features for the station auxiliary transformers and downstream circuits and are controlled by the plant operators. Ginna Station relies upon the RG&E Energy Control Center to determine the status of 34.5 kV power from Stations 204 and 13A. Procedural guidance for restoration of offsite power does not address the control of circuit breakers upstream of 52/76702 and 52/75112.

Based on the applicant's response, the bulk of Ginna's plant system electrical services are provided by 34.5 kV circuit breakers 52/76702 and 52/75112 located in the plant's onsite transformer yard. The staff, therefore, agrees that those breakers provide the appropriate boundary for the portion of the offsite circuits to be included within the scope of license renewal.

2.5.1.5.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's response to the staff's RAI to determine whether any electrical and I&C commodity groups that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified the switchyard buses that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified the switchyard buses that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.5.1.6 Transmission Conductors

2.5.1.6.1 Summary of Technical Information in the Application

The applicant described the transmission conductors commodity group in LRA Section 2.5.1.

Transmission conductors are uninsulated, stranded electrical cables used in switchyards, switching stations, and transmission lines to connect two or more elements of an electrical power circuit, such as disconnect switches, power circuit breakers, transformers, and switchyard buses. At Ginna Station, transmission conductors are used to supply the onsite 34.5 kV switchyard from multiple offsite substations. The LRA states that these components are not included in the license renewal boundary because they are primarily located offsite. It concludes, therefore, that an AMR of transmission conductors is not required.

2.5.1.6.2 Staff Evaluation

The staff reviewed LRA Sections 2.5.1 and 2.4.3, UFSAR Sections 8.1, 8.2, and 8.3, and the applicant's responses to the staff's RAIs. The purpose of the review was to determine whether there is reasonable assurance that the transmission conductors within the scope of license renewal and subject to an AMR had been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

In the performance of the review, the staff selected the nonessential buildings/areas identified in LRA Section 2.4.3 to verify that transmission conductors having intended functions that might be located in those spaces were not omitted from the scope of the Rule. This is consistent with the treatment of the transmission conductors as a commodity utilizing the "plant spaces" approach. The staff focused on transmission conductors that were not identified as being subject to an AMR to determine if any transmission conductors were omitted.

In a conference call with the applicant on January 15, 2003, the applicant stated that electrical and I&C components located within the plant spaces identified in LRA Section 2.4.3 do not perform any license renewal intended functions and, therefore, are not included within the scope of license renewal. The staff reviewed the plant spaces (buildings/areas) identified in LRA Section 2.4.3 against information contained in the Ginna UFSAR. The staff did not find any indication in the UFSAR that these spaces contain electrical or I&C components (including transmission conductors) that perform a license renewal intended function. In addition, selected buildings/areas identified in LRA Section 2.4.3 were audited during the NRC license renewal inspections. The inspector toured selected SCs listed in Section 2.4.3 of the LRA, including Items (a), (b), (d), (f), (n), (s), and (t), and determined that there were no electrical components in them. Buildings (u) and (e) could not be entered because they were sealed with the radioactive components.

With regard to plant spaces that do include electrical and I&C components that perform a license renewal intended function, LRA Section 2.1.7.4 indicates that component specific scoping may be performed in those spaces. This is done to limit the number of components for which aging management activities are required, or to eliminate aging management activities altogether if nothing remains in that particular material/environment group population.

The staff asked the applicant to identify each of the electrical and I&C components (including transmission conductors) that were eliminated from aging management activities through component specific scoping, and to identify the plant SSCs that are served by those components. The applicant was also asked to provide the basis used in each case for concluding that those SSCs do not provide any license renewal intended functions identified in 10 CFR 54.4(a). The response to the staff's request was provided by the applicant in a letter dated May 23, 2003. There were no components identified by the applicant in the transmission conductor category that were eliminated from aging management activities through component specific scoping.

Transmission conductors are often used in the offsite power circuits that are required to be included within the scope of license renewal, consistent with the requirements in 10 CFR 54.4(a)(3) relative to SBO. With regard to the offsite power circuits, Section 2.5.8 of the LRA indicates that the 115 kV switchyard (Station 13A) is not included within the scope of license renewal. The information in the application also indicates that the 34.5 kV switchyard (Station 204) is not included within the scope of license renewal. In the Ginna design, there are two 34.5 kV circuit breakers shown in UFSAR Figure 8.1-1—upstream of station auxiliary (startup) transformers 12A and 12B and between the transformers and their respective switchyards (Stations 204 and 13A).

The staff guidance, "Scoping of Equipment Relied On to Meet the Requirements of the SBO Rule (10 CFR 50.63) for License Renewal (10 CFR 54.4(a)(3))," was provided to the Nuclear Energy Institute and the Union of Concerned Scientists in a letter dated April 1, 2002. The guidance states that—

> For purposes of the license renewal rule, the staff has determined that the plant system portion of the offsite power system that is used to connect the plant to the offsite power source should be included within the scope of the rule. This path typically includes the switchyard circuit breakers that connect to the offsite system power transformers (startup transformers), the transformers themselves, the intervening overhead or underground circuits between circuit breaker and transformer and transformer and the onsite electrical distribution system, and the associated control circuits and structures.

The Ginna offsite power system design is not configured like the typical design described in the guidance. It has the intervening 34.5 kV circuit breakers between the switchyard circuit breakers and the startup (station auxiliary) transformers. In order for the staff to determine whether the plant system portion of the offsite power system should end with the 34.5 kV circuit breakers or with the upstream switchyard circuit breakers at Stations 13A and 204, the staff needed to determine which circuit breakers provided the bulk of the plant system electrical services (e.g., providing plant power, protecting downstream circuits, and providing plant operator-controlled isolation and energization capability). Both groups of circuit breakers clearly provide power to the plant. The applicant was asked to indicate which group of breakers are tripped upon actuation of the electrical protective features for the station auxiliary transformers and downstream circuits, and which group can be tripped open or closed by the Ginna plant operator.

If the bulk of the plant system electrical services were provided by the switchyard circuit breakers and not the 34.5 kV breakers, the applicant was asked to provide the basis for concluding that the plant system portion of the offsite power system ends with the 34.5 kV circuit breakers rather than the switchyard circuit breakers.

The applicant provided the following response in its May 23, 2003, letter:

> Circuit breakers 52/76702 and 52/75112 are located in the onsite transformer yard. These circuit breakers are tripped upon actuation of the electrical protective features for the station auxiliary transformers and downstream circuits and are controlled by the plant operators. Ginna Station relies upon the RG&E Energy Control Center to determine the status of 34.5 kV power from Stations 204 and 13A. Procedural guidance for restoration of offsite power does not address the control of circuit breakers upstream of 52/76702 and 52/75112.

Based on the applicant's response, the bulk of the Ginna's plant system electrical services are provided by 34.5 kV circuit breakers 52/76702 and 52/75112 located in the plant's onsite transformer yard. The staff, therefore, agrees that those breakers provide the appropriate boundary for the portion of the offsite circuits to be included within the scope of license renewal.

2.5.1.6.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's response to the staff's RAI to determine whether any electrical and I&C commodity groups that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified the transmission conductors that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified the transmission conductors that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.5.1.7 Uninsulated Ground Connectors

2.5.1.7.1 Summary of Technical Information in the Application

The applicant described the uninsulated ground conductors commodity group in LRA Section 2.5.1.

Uninsulated ground conductors are electrical conductors (e.g., copper cable, copper bar, steel bar) that are uninsulated (bare) and are used to make ground connections for electrical equipment. Uninsulated ground conductors are connected to electrical equipment housings and electrical enclosures, as well as metal structural features such as the cable tray system and building structural steel. Uninsulated ground conductors are always isolated or insulated from the electrical operating circuits. Uninsulated ground conductors enhance the capability of the electrical system to withstand electrical system faults disturbances (e.g., electrical faults, lightening surges) for equipment and personnel protection. The LRA states that there are no license renewal intended functions for uninsulated ground conductors used at Ginna Station.

2.5.1.7.2 Staff Evaluation

The staff reviewed LRA Section 2.5.1 and UFSAR Sections 8.1, 8.2, and 8.3 to determine whether there is reasonable assurance that the uninsulated ground connector components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

The staff reviewed UFSAR Sections 8.1, 8.2, and 8.3 to determine whether uninsulated ground conductors are used for any electrical purposes other than those identified in Ginna LRA Section 2.5.1. The staff found no other purposes identified. The staff agrees with the applicant that the intended purposes of the uninsulated ground conductors identified in LRA Section 2.5.1 do not serve a license renewal intended function at Ginna.

2.5.1.7.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's response to the staff's RAI to determine whether any electrical and I&C commodity groups that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the uninsulated ground conductors at Ginna do not serve a license renewal intended function, as required by 10 CFR 54.4(a).

2.5.1.8 High-Voltage Insulators

2..5.1.8.1 Summary of Technical Information in the Application

The applicant described the high-voltage insulators commodity group in LRA Section 2.5.1. Table 2.5.8-1 identifies the system which contains this commodity group, as well as the passive function and aging management references for the commodity group.

An insulator is a material in a form designed to (1) support a conductor physically and (2) separate the conductor electrically from another conductor or object. The insulators evaluated for license renewal are those used to support and insulate high-voltage electrical components in switchyards, switching stations, and transmissions, such as transmission conductors and switchyard buses. The license renewal intended function of these components is to insulate and support electrical conductors.

2.5.1.8.2 Staff Evaluation

The staff reviewed LRA Sections 2.5.1 and 2.4.3, UFSAR Sections 8.1, 8.2, and 8.3, and the applicant's responses to the staff's RAIs. The purpose of the review was to determine whether there is reasonable assurance that the high-voltage insulators within the scope of license renewal and subject to an AMR had been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

In the performance of the review, the staff selected the nonessential buildings/areas identified in LRA Section 2.4.3 to verify that the high-voltage insulators having intended functions that might be located in those spaces were not omitted from the scope of the Rule. This is consistent with the treatment of the high-voltage insulators as a commodity utilizing the "plant spaces" approach. The staff focused on high-voltage insulators that were not identified as being subject to an AMR to determine if any high-voltage insulators were omitted.

In a conference call with the applicant on January 15, 2003, the applicant stated that electrical and I&C components located within the plant spaces identified in LRA Section 2.4.3 do not perform any license renewal intended functions and, therefore, are not included within the scope of license renewal. The staff reviewed the plant spaces (buildings/areas) identified in LRA Section 2.4.3 against information contained in the Ginna UFSAR. The staff did not find any indication in the UFSAR that these spaces contain electrical or I&C components (including high-voltage insulators) that perform a license renewal intended function. In addition, selected buildings/areas identified in LRA Section 2.4.3 were audited during the NRC license renewal inspections. The inspector toured selected SCs listed in Section 2.4.3 of the LRA, including Items (a), (b), (d), (f), (n), (s), and (t), and determined that there are no electrical components in them. Buildings (u) and (e) could not be entered because they were sealed with the radioactive components.

With regard to plant spaces that do include electrical and I&C components that perform a license renewal intended function, LRA Section 2.1.7.4 indicates that component specific scoping may be performed in those spaces. This is done to limit the number of components for which aging management activities are required, or to eliminate aging management activities altogether if nothing remains in that particular material/environment group population.

The staff asked the applicant to identify each of the electrical and I&C components (including high-voltage insulators) that were eliminated from aging management activities through component specific scoping, and to identify the plant SSCs that are served by those components. The applicant was also asked to provide the basis used in each case for concluding that those SSCs do not provide any license renewal intended functions identified in 10 CFR 54.4(a). The response to the staff's request was provided by the applicant in a letter dated May 23, 2003. The response identified the high-voltage insulators that were eliminated from aging management activities through component specific scoping. The following high-voltage insulators were identified, and the justification for their elimination was provided:

- 115 kV high-voltage insulators are located in the offsite power system to support the 115 kV switchyard bus and related components. These insulators and the equipment

> supported do not perform an intended function. With regard to interim staff guidance on SBO, these insulators are not required to recover from an SBO event.

The staff agrees with the applicant that these high voltage insulators do not serve a license renewal intended function.

High-voltage insulators are often used in the offsite power circuits that are required to be included within the scope of license renewal, consistent with the requirements in 10 CFR 54.4(a)(3) relative to SBO. With regard to the offsite power circuits, Section 2.5.8 of the application indicates that the 115 kV switchyard (Station 13A) is not included within the scope of license renewal. The information in the application also indicates that the 34.5 kV switchyard (Station 204) is not included within the scope of license renewal. In the Ginna design, there are two 34.5 kV circuit breakers shown in UFSAR Figure 8.1-1—upstream of station auxiliary (startup) transformers 12A and 12B and between the transformers and their respective switchyards (Stations 204 and 13A).

The staff guidance, "Scoping of Equipment Relied On to Meet the Requirements of the SBO Rule (10 CFR 50.63) for License Renewal (10 CFR 54.4(a)(3))," was provided to the Nuclear Energy Institute and the Union of Concerned Scientists in a letter dated April 1, 2002. The guidance states that—

> For purposes of the license renewal rule, the staff has determined that the plant system portion of the offsite power system that is used to connect the plant to the offsite power source should be included within the scope of the rule. This path typically includes the switchyard circuit breakers that connect to the offsite system power transformers (startup transformers), the transformers themselves, the intervening overhead or underground circuits between circuit breaker and transformer and transformer and the onsite electrical distribution system, and the associated control circuits and structures.

The Ginna offsite power system design is not configured like the typical design described in the guidance. It has the intervening 34.5 kV circuit breakers between the switchyard circuit breakers and the startup (station auxiliary) transformers. In order for the staff to determine whether the plant system portion of the offsite power system should end with the 34.5 kV circuit breakers or with the upstream switchyard circuit breakers at Stations 13A and 204, the staff needed to determine which circuit breakers provided the bulk of the plant system electrical services (providing plant power, protecting downstream circuits, and providing plant operator-controlled isolation and energization capability). Both groups of circuit breakers clearly provide power to the plant. The applicant was asked to indicate which group of breakers are tripped upon actuation of the electrical protective features for the station auxiliary transformers and downstream circuits, and which group can be tripped open or closed by the Ginna plant operator.

If the bulk of the plant system electrical services were provided by the switchyard circuit breakers and not the 34.5 kV breakers, the applicant was asked to provide the basis for concluding that the plant system portion of the offsite power system ends with the 34.5 kV circuit breakers rather than the switchyard circuit breakers.

The applicant provided the following response in its May 23, 2003, letter:

> Circuit breakers 52/76702 and 52/75112 are located in the onsite transformer yard. These circuit breakers are tripped upon actuation of the electrical protective features for the station auxiliary transformers and downstream circuits and are controlled by the plant operators. Ginna Station relies upon the RG&E Energy Control Center to determine the status of 34.5 kV power from Stations 204 and 13A. Procedural guidance for restoration of offsite power does not address the control of circuit breakers upstream of 52/76702 and 52/75112.

Based on the applicant's response, the bulk of Ginna's plant system electrical services are provided by 34.5 kV circuit breakers 52/76702 and 52/75112 located in the plant's onsite transformer yard. The staff therefore agrees that those breakers provide the appropriate boundary for the portion of the offsite circuits to be included within the scope of license renewal.

2.5.1.8.3 Conclusions

The staff reviewed the LRA, the supporting information in the Ginna UFSAR, and the applicant's response to the staff's RAI to determine whether any electrical and I&C commodity groups that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified the high-voltage insulators that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified the high-voltage insulators that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.5.2 Evaluation Findings

On the basis of this review, the staff concludes that there is reasonable assurance that the applicant has adequately identified the electrical and I&C components that are within the scope of license renewal, in accordance with the requirements of 10 CFR 54.4(a), and adequately identified the AMR, in accordance with the requirements of 10 CFR 54.21(a)(1).

3. AGING MANAGEMENT REVIEW

3.0 Aging Management Review Results

Rochester Gas & Electric Corporation (RG&E) fully utilized the Generic Aging Lessons Learned (GALL) process in preparing its license renewal application (LRA). The purpose of GALL is to provide the staff with a summary of staff-approved aging management programs (AMPs) for the aging of most structures and components that are subject to an aging management review (AMR). If an applicant commits to implementing these staff-approved AMPs, the time, effort, and resources used to review an applicant's LRA will be reduced, thereby improving the efficiency and effectiveness of the license renewal review process.

The GALL Report (NUREG-1801) is a compilation of existing programs and activities used by commercial nuclear power plants that were reviewed and evaluated by the staff for managing the aging effects of structures and components within the scope of license renewal which are subject to an AMR. The GALL Report summarizes the aging management evaluations, programs, and activities credited for managing aging for most of the structures and components used throughout the industry and serves as a reference for both applicants and staff reviewers to quickly identify those AMPs and activities that the staff has determined will provide adequate aging management during the period of extended operation.

The GALL Report identifies (1) systems, structures, and components; (2) component materials; (3) the environments to which the components are exposed; (4) the aging effects associated with the materials and environments; (5) the AMPs that are credited with managing the aging effects; and (6) recommendations for further applicant evaluations of aging effects and their management for certain specific component types.

In order to determine whether the GALL process would improve the efficiency of the license renewal review, the staff 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. The standard review plan for license renewal (SRP-LR) was prepared based on both the GALL model and the lessons learned from the demonstration project.

During its review of the RG&E LRA, the staff performed an AMR inspection (Inspection Report 50-244/2003-008) from July 21–25, 2003, and from August 4–8, 2003. The purpose of the inspection was to examine activities that support the LRA. The inspection consisted of a selected examination of procedures, representative records, and interviews with the applicant regarding proposed aging management activities. The team also reviewed the proposed implementation of AMPs credited in the LRA for managing aging. The results of the inspection can be found in the staff's inspection report dated December 2, 2003.

The staff also performed an AMP audit on June 24 and 25, 2003. The audit team reviewed those AMPs credited in the LRA for managing aging that the applicant claimed to be consistent with GALL. The audit team evaluated each of the 10 attributes of the applicant's AMP, which the applicant claimed were consistent with the attributes of the associated AMP described in the

GALL Report. Those AMPs that were not claimed to be consistent with the GALL Report, and those attributes that were deviations from the attributes described in the GALL Report AMPs, were provided to the staff for review. The audit team identified that the Fire Protection Program attributes for parameters monitored/inspected and detection of aging effects were not consistent with GALL as stated in the LRA. In addition, inconsistencies were identified in the Fire Water System Program attributes for detection of aging effects and parameters monitored/inspected. The team concluded that, with the exception of the Fire Protection Program and the Fire Water System Program, the applicant's AMPs were consistent with the GALL Report AMPs with differences/exceptions as stated in the LRA and the requests for additional information (RAIs).

During the AMP audit, the staff also performed a separate audit of some specific issues such as reviewing the plant spaces (buildings/areas) identified in LRA Section 2.4.3 against information contained in the Ginna Updated Final Safety Analysis Report (UFSAR). The AMP review and audit of specific issues can be found in the staff's AMP audit report, dated September 8, 2003, and are addressed in this safety evaluation report (SER).

As a result of the staff's review of the RG&E application for license renewal, including the additional information and clarifications submitted subsequently, the staff identified two proposed license conditions. The first license condition requires the applicant to include the UFSAR Supplement in the next UFSAR update required by Title 10, Section 50.71(e), of the *Code of Federal Regulations* (10 CFR 50.71(e)) following issuance of the renewed license. The second license condition requires that the future activities identified in the UFSAR Supplement be completed prior to the period of extended operation.

3.0.1 The GALL Format for the LRA

The Ginna Nuclear Power Plant LRA closely follows the standard LRA format, as agreed between the Nuclear Energy Institute (NEI) and the staff (see letters dated August 9, 1999, and September 22, 1999). This format has been used by previous applicants and will continue to be used by future applicants. However, there are several important changes within the format that reflect the GALL process. First, the tables in LRA Section 2 that identify the structures and components that are subject to an AMR now include a third column that links plant-specific structures and components in the Section 2 tables to generic GALL component groups in Section 3 (discussed in detail below). Second, the tables in LRA Section 3 are different from the Section 3 tables used in previous LRAs. There are no system-specific tables in Section 3 of the Ginna LRA. The individual components within a system have been included in a series of system group tables. For example, there are 20 auxiliary systems at Ginna. Each system has several components. In previous LRAs, each system had a separate table that listed the components in the system. With the Ginna LRA, there are no system tables. Instead all the components in the 20 auxiliary systems are included in any one of two auxiliary system tables. Table 3.4-1 of the LRA consists of auxiliary system components evaluated in the GALL Report, and LRA Table 3.4-2 consists of auxiliary system components not evaluated in the GALL Report. Similarly, the LRA tables for the other system groups (3.2—reactor coolant systems, 3.3—engineered safety features systems, 3.5—steam and power conversion systems, 3.6—structures and component supports, and 3.7—electrical and instrumentation and controls systems) have 3.x-1 LRA tables for components evaluated in the GALL Report and 3.x-2 LRA tables for components not evaluated in the GALL Report.

The 3.x-1 tables provide information regarding AMPs that are consistent with the GALL Report. The first four columns of Table 3.x-1 are derived from Tables 3.1-1 through 3.1-6 of the SRP-LR. Included in this table is a discussion column. The discussion column provides a conclusion indicating if the aging management evaluation results are consistent with GALL, along with any clarifications or explanations required to support the conclusion, if the conclusion is different than those of the GALL Report. For a determination to be made that a table line item is consistent with GALL, several criteria must be met. First, the plant-specific component is reviewed against the GALL Report to ensure that the component, materials of construction, and internal or external service environments are comparable to those described in a particular GALL item. Second, for those that are comparable, the results of the plant aging management review/aging effect evaluation are compared to the aging effects/mechanisms in the GALL Report. Finally, the programs credited in the GALL Report for managing those aging effects are compared to the programs described in the plant evaluation. If, using good engineering judgment, it could be reasonably concluded that the plant evaluation is in agreement with the GALL evaluation, a line item was considered consistent with GALL or NUREG-1801. There are cases where components, and component material/environment combinations, and aging effects are common between a NUREG-1801 line item and the plant evaluation, but the AMP selections differ. In those cases, the discussion column indicates the plant AMP selection, but no conclusion is made that the line item is consistent with the GALL Report.

The 3.x-2 tables provide information regarding AMPs that are different from or not addressed in the GALL Report. A plant component is considered not addressed by the NUREG if the component type is not evaluated in the GALL Report or has a different material of construction or operating environment than evaluated in the GALL.

The 3.x-2 tables are different from the 3.x-1 tables. The 3.x-2 tables include the component types, materials, environments, aging effects requiring management, the programs and activities for managing aging, and a discussion column. Because these structures and components were not evaluated in GALL, the staff performed a review, similar to those done for past applications.

3.0.2 The Staff's Review Process

The staff's review of the Ginna LRA was performed in three phases. In Phase 1, the staff reviewed the applicant's AMP descriptions to compare those AMPs for which the applicant claimed consistency with those reviewed and approved in the GALL Report. For those AMPs for which the applicant claimed consistency with the GALL AMPs, and for which GALL recommended no further evaluation, the staff conducted an audit to confirm that the applicant's AMPs were consistent with the GALL AMPs. For those AMPs that were not consistent with GALL, or were not addressed in GALL, the staff's review determined whether the AMPs were adequate to manage the aging effects for which they were credited.

Several Ginna AMPs were described by the applicant as being consistent with GALL but with some deviation from GALL. By letter dated March 21, 2003, the staff issued RAI 3.0-1, requesting the applicant to define the AMP deviations contained in the LRA. By letter dated May 23, 2003, the applicant addressed this RAI by defining the following two types of AMP deviations:

(1) Exceptions to GALL—"those that do not agree with, or do not implement, recommendations in GALL program elements"

(2) Enhancements to GALL—"those that augment the GALL program element recommendations"

For each AMP that had one or more of these deviations, the staff reviewed each deviation to determine (1) whether the deviation is acceptable and (2) whether the AMP, as modified, would adequately manage the aging effect(s) for which it is credited.

For those AMPs that are not evaluated in GALL, the staff evaluated the AMP against the 10 program elements found in Branch Technical Position RLSB-1 in Section A-1 of the SRP-LR Appendix A (NUREG-1800).

The staff also reviewed the UFSAR Supplement for each AMP to determine whether it provided an adequate summary description of the program or activity, as required by 10 CFR 54.21(d).

The AMRs and associated AMPs in the GALL Report fall into two broad categories—those AMRs and associated AMPs that GALL concludes are adequate to manage aging of the components referenced in GALL, and those AMRs and associated AMPs for which GALL concludes that aging management is adequate, but further evaluation must be done for certain aspects of the aging management process. In Phase 2, the staff compared the applicant's AMR results and associated AMPs to the AMR results and associated AMPs in GALL, to determine whether the applicant's AMRs and associated AMPs were consistent with those reviewed and approved in the GALL Report. For those AMRs and associated AMPs for which GALL recommended further evaluation, the staff reviewed the applicant's evaluation to determine whether it addressed the additional issues recommended in the GALL Report. Finally, for AMRs and associated AMPs that were not consistent with GALL, the staff's review determined whether the AMRs and associated AMPs were adequate to manage the aging effects for which they were credited.

Once the staff determined that the applicant's AMRs and associated AMPs were adequate to manage aging, it performed Phase 3 of its review by reviewing plant-specific structures and components to determine whether the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions 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). Specifically, this review involved a component-by-component review to determine whether the applicant properly applied the GALL program to the aging management of components within the scope of license renewal and subject to an AMR (i.e., the staff evaluated whether the applicant had properly identified the aging effects, and the AMPs credited for managing the aging effects, for each RG&E structure and component within the scope of license renewal and subject to an AMR). For structures and components evaluated in GALL, the staff reviewed the adequacy of aging management against the GALL criteria. For structures and components not evaluated in GALL, the staff reviewed the adequacy of aging management against the 10 criteria in Appendix A to the SRP-LR. Some RG&E structures and components were not evaluated in GALL, but the applicant determined that the GALL AMR results could be applied to these structures and components and provided justification to support this determination. In these cases, the staff reviewed the adequacy of aging management against the GALL criteria to determine whether the GALL AMPs were adequate to manage the aging effects for which they were credited.

3.0.3 Aging Management Programs

Table 3.0.3-1 presents the common AMPs, the associated GALL program, 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 3.0.3-1 also lists programs that were described in the license renewal application that the applicant stated are not included as one of Ginna's aging management programs.

Table 3.0.3-1 Common Aging Management Programs

Applicant's AMP (LRA Section)	**Associated GALL AMP**	**LRA System Groups That Credit the AMP for Aging Management**	**Staff Evaluation (SER Section)**
Water Chemistry Control (B2.1.37)	XI.M2	3.1—RCS 3.2—ESF 3.3—Auxiliary 3.4—Steam and Power Conversion 3.5—Structures	3.0.3.1
ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection (B2.1.2)	XI.M1	3.1—RCS 3.2—ESF 3.3—Auxiliary 3.5—Structures	3.0.3.2
Bolting Integrity (B2.1.5)	XI.M18	3.1—RCS 3.2—ESF 3.3—Auxiliary 3.4—Steam and Power Conversion 3.5—Structures	3.0.3.3
Boric Acid Corrosion (B2.1.6)	XI.M10	3.1—RCS 3.2—ESF 3.3—Auxiliary 3.4—Steam and Power Conversion 3.5—Structures 3.6—Electrical	3.0.3.4
Closed-Cycle (Component) Cooling Water System (B2.1.9)	XI.M21	3.2—ESF 3.3—Auxiliary	3.0.3.5
Flow-Accelerated Corrosion (B2.1.15)	XI.M17	3.3—Auxiliary 3.5—Steam and Power Conversion	3.0.3.6

Applicant's AMP (LRA Section)	Associated GALL AMP	LRA System Groups That Credit the AMP for Aging Management	Staff Evaluation (SER Section)
One-Time Inspection (B2.1.21)	XI.M32	3.1—RCS 3.2—ESF 3.3—Auxiliary 3.4—Steam and Power Conversion 3.6—Electrical	3.0.3.7
Periodic Surveillance and Preventive Maintenance (B2.1.23)	Plant specific	3.1—RCS 3.2—ESF 3.3—Auxiliary 3.4—Steam and Power Conversion 3.5—Structures	3.0.3.8
Selective Leaching of Materials (B2.1.29)	XI.M33	3.2—ESF 3.3—Auxiliary	3.0.3.9
Structures Monitoring (B2.1.32)	XI.S5, SI.S6, SI.S7	3.3—Auxiliary 3.5—Structures	3.0.3.10
System Monitoring (B2.1.33)	Plant specific	3.1—RCS 3.2—ESF 3.3—Auxiliary 3.4—Steam and Power Conversion 3.5—Structures	3.0.3.11
Thermal Aging and Neutron Embrittlement of Austenitic Stainless Steel (B2.1.35)	XI.M13	Not applicable	3.0.3.12.1
Buried Piping and Tank Surveillance (B2.1.8)	XI.M28	Not applicable	3.0.3.12.2
Compressed Air Monitoring (B2.1.10)	XI.M24	Not applicable	3.0.3.12.3
Inaccessible Medium-Voltage Cables Not Subject to EQ (B2.1.17)	XI.E3	Not applicable	3.0.3.12.4
Loose Parts Monitoring (B2.1.19)	XI.M14	Not applicable	3.0.3.12.5
Neutron Noise Monitoring (B2.1.20)	XI.M15	Not applicable	3.0.3.12.6
Protective Coatings Monitoring and Maintenance (B2.1.24)	XI.S8	Not applicable	3.0.3.12.7

Table 3.0.3-2 presents the system-specific AMPs, the associated GALL program, 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 3.0.3-2 System-Specific Management Programs

Applicant's AMP (LRA Section)	Associated GALL AMP	LRA System Groups That Credit the AMP for Aging Management	Staff Evaluation (SER Section)
Reactor Head Closure Studs (B2.1.25)	XI.M3	3.1—RCS	3.1.2.3.1
Nickel-Alloy Nozzles and Penetrations Inspection Program (B2.1.26)	XI.M11	3.1—RCS	3.1.2.3.2
Reactor Vessel Internals (B2.1.27)	XI.M16	3.1—RCS	3.1.2.3.3

Applicant's AMP (LRA Section)	Associated GALL AMP	LRA System Groups That Credit the AMP for Aging Management	Staff Evaluation (SER Section)
Reactor Vessel Surveillance (B1.1.28)	XI.M31	3.1—RCS	3.1.2.3.4
Steam Generator Integrity (B2.1.31)	XI.M19	3.1—RCS	3.1.2.3.5
Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (B2.1.34)	XI.M12	3.1—RCS	3.1.2.3.6
Thimble Tube Inspection (B2.1.36)	Plant specific	3.1—RCS	3.1.2.3.7
Fatigue Monitoring (B3.2)	X.M1	3.1—RCS	3.1.2.3.8
Buried Piping and Tank Inspection (B2.1.7)	XI.M34	3.3—Auxiliary	3.3.2.3.1
Fire Protection (B2.1.13)	XI.M26	3.3—Auxiliary	3.3.2.3.2
Fire Water System (B2.1.14)	XI.M27	3.3—Auxiliary	3.3.2.3.3
Fuel Oil Chemistry (B2.1.16)	XI.M30	3.3—Auxiliary	3.3.2.3.4
Heavy and Light Load (Related to Refueling) Handling Systems (B2.1.18)	XI.M23	3.3—Auxiliary	3.3.2.3.5
Open-Cycle Cooling (Service) Water (B2.1.22)	XI.M20	3.3—Auxiliary	3.3.2.3.6
Spent Fuel Pool Neutron Absorbing Monitoring (B2.1.30)	XI.M22	3.3—Auxiliary	3.3.2.3.7
Aboveground Carbon Steel Tanks (B2.1.1)	XI.M29	3.3—Auxiliary	3.3.2.3.8
ASME Section XI, Subsections IWE and IWL Inservice Inspection (B2.1.3)	XI.S1, XI.S2, XI.S4	3.5—Structures	3.5.2.3.1
ASME Section XI, Subsection IWF, Inservice Inspection (B2.1.4)	XI.S3	3.5—Structures	3.5.2.3.2
Concrete Containment Tendon Prestress (B3.3)	X.S1	3.5—Structures	3.5.2.3.3
Electrical Cables and Connections Not Subject to EQ (B2.1.11)	XI.E1	3.6—Electrical	3.6.2.3.1
Electric Cables Not Subject to EQ Used in Instrumentation Circuits (B2.1.12)	XI.E2	3.6—Electrical	3.6.2.3.2
Environmental Qualification (B3.1)	X.E1	3.6—Electrical	3.6.2.3.3
Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	XI.E3	3.6—Electrical	3.6.2.3.4

3.0.3.1 Water Chemistry Control Program

3.0.3.1.1 Summary of Technical Information in the Application

The applicant's Water Chemistry Control Program is discussed in LRA Section B2.1.37, "Water Chemistry Control." In that section, the applicant described its AMP to manage aging effects in the systems carrying the primary and secondary water. The LRA stated that this AMP is consistent with GALL AMP XI.M2, "Water Chemistry," including the need for verification of the program by performing a one-time inspection of the selected components in the low-flow or stagnant portions of a system. The components exposed to a high-velocity flow are not included in the one-time inspection because the dominant corrosion mechanism in these components is flow-accelerated corrosion which is addressed in the Flow-Accelerated Corrosion Program. The one-time inspection of the components at susceptible locations will provide verification of the effectiveness of the Water Chemistry Control Program. This inspection is covered within the scope of the LRA Section B2.1.21, "One-Time Inspection."

Aging effects managed by the program include loss of material due to general corrosion, pitting, and crevice corrosion, microbiologically influenced corrosion (MIC), stress-corrosion cracking (SCC), and fouling due to corrosion product buildup. The applicant stated that the effectiveness of the Water Chemistry Control Program will be verified by a One-Time Inspection Program of selected susceptible components in low-flow or stagnant portions of the system.

In the LRA, the applicant concluded that the Water Chemistry Control Program ensures that aging effects caused by primary and secondary water chemistries will be adequately managed.

3.0.3.1.2 Staff Evaluation

During the audit, the staff confirmed the applicant's claim of consistency of the AMP with the GALL program. In addition, for Ginna, the staff determined whether the applicant properly applied the GALL program to its facility. Furthermore, the staff reviewed the UFSAR Supplement and found that it provides an adequate description of the revised program.

3.0.3.1.3 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that this program is consistent with the GALL program. Therefore, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of structures and components (SCs) subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

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

3.0.3.2.1 Summary of Technical Information in the Application

The applicant's American Society of Mechanical Engineers (ASME) Section XI, Inservice Inspection Program is discussed in LRA Section B2.1.2, "ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program." The LRA stated that the program is consistent with GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," with no deviations.

This AMP is credited with managing aging effects in Class 1, 2, and 3 components and their integral attachments in the reactor coolant systems (RCS), engineered safety features (ESF) systems, auxiliary systems, and steam and power conversion systems (SPCS).

According to 10 CFR 50.55a, light-water cooled power plants are required to meet the inservice inspection (ISI) requirements of ASME Boiler and Pressure Vessel Code, Section XI, for Class 1, 2, and 3 pressure-retaining components and their integral attachments.
The applicant's program performs inspection, repair, and replacement of these components in accordance with Subsections IWB, IWC, and IWD, respectively, of the 1995 edition of the code and the 1996 addenda. The applicant's program also includes periodic visual, surface, and/or volumetric examinations and leakage tests of all Class 1, 2, and 3 pressure-retaining components and their integral attachments, including welds, pump casings, valve bodies, and pressure-retaining bolting.

The LRA stated that the ASME Section XI Inservice Inspection Program meets the requirements outlined in Subsections IWB, IWC, and IWD, and has been effective in managing the effects of aging in Class 1, 2, and 3 components and their integral attachments.

The applicant also stated that Ginna has maintained an Inservice Inspection Program in accordance with 10 CFR 50.55a and its plant technical specification requirements. The fourth 10-year interval of the Ginna Inservice Inspection Program began on January 1, 2000.
The program was developed and prepared to meet the requirements of ASME Section XI, 1995 Edition and 1996 Addenda.

The applicant performed a review of industry operating experience of incidents of primary pressure boundary degradation that were revealed by ISIs and reported through NRC generic communications. The applicant grouped the incidents into the following categories:

- boric acid corrosion due to leakage at bolted closures and leakage caused by cracking of primary pressure boundary Alloy 600 components such as reactor vessel head control rod drive mechanism (CRDM) nozzles

- cracking due to SCC in safety injection piping, instrument nozzles in safety injection accumulators, and safety-related stainless steel piping systems containing stagnant borated water

- crack initiation and growth due to thermal and mechanical loading in high-pressure injection and safety injection lines

- degradation of steam generator tubing due to primary water stress-corrosion cracking (PWSCC), outer-diameter stress-corrosion cracking (ODSCC), intergranular attack (IGA), wastage and pitting and denting and cracking of steam generator shell welds

The applicant reviewed Ginna's plant-specific operating experiences and credits the Inservice Inspection Program examinations with discovering the following conditions:

- bolting degradation detected by visual test (VT)-1 examinations and boric acid leakage by VT-2 leakage examinations
- PWSCC, ODSCC, IGA, and denting of Alloy 600 steam generator tubing by eddy current examinations
- shallow thermal fatigue cracks in steam generator feedwater nozzle-to-pipe weld
- original manufacturing flaw indications in the primary inlet nozzle-to-reactor vessel weld (N2B) and pressurizer lower head-to-shell girth weld were evaluated by fracture mechanics and determined to be acceptable

The LRA stated that the Inservice Inspection Program at Ginna is continually upgraded to account for industry experience and research and is subjected to periodic NRC inspections and self-assessments. The applicant concluded that the Inservice Inspection Program at Ginna has provided an effective means of assuring the pressure integrity of Class 1, 2, and 3 systems at Ginna.

In its LRA, the applicant concluded that the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program is consistent with the GALL Report and that continued implementation of the Inservice Inspection Program ensures that aging effects will be managed such that the intended functions of Class 1, 2, and 3 pressure-retaining components and their integral attachments will be maintained during the license renewal period.

3.0.3.2.2 Staff Evaluation

The staff confirmed the applicant's claim that the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program is consistent with GALL during the AMP audit.
In addition, for Ginna, the staff determined whether the applicant properly applied the GALL program to its facility. The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program and found it to be acceptable.

3.0.3.2.3 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that this program is consistent with the GALL Report. Therefore, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.0.3.3 Bolting Integrity Program

3.0.3.3.1 Summary of Technical Information in the Application

The applicant's Bolting Integrity Program is discussed in LRA Section B2.1.25, "Reactor Head Closure Studs," and B2.1.5, "Bolting Integrity." The applicant stated that the program is consistent with GALL Program XI.M18, "Bolting Integrity," with no deviations. The applicant also states that its Bolting Integrity Program credits activities performed under the direction of other AMPs for managing specific aging effects. These programs include the following:

- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, 1995 Edition with 1996 Addenda
- ASME Section XI, Subsection IWF Inservice Inspection Program
- Periodic Surveillance and Preventive Maintenance Program
- Boric Acid Corrosion Program
- Systems Monitoring Program
- Structures Monitoring Program

This AMP is credited with managing aging of all bolting on mechanical and structural components within the scope of license renewal. The program consists of periodic inspections of pressure-retaining bolting as delineated in NUREG-1339, and other industry recommendations such as in Electric Power Research Institute (EPRI) NP-5679 (with exceptions noted in NUREG-1339) for safety-related bolting, and EPRI TR-104213 for pressure-retaining and structural bolting. The program provides for periodic inspection of closure bolting for indication of loss of preload, cracking, and loss of material.

The applicant's plant-specific operating experience has revealed bolting degradation resulting from boric acid leakage in borated systems, failure of American Society of Testing and Materials (ASTM) A-90 high-strength reactor coolant pump (RCP) leg-support anchor bolts due to SCC, and linear indications in machine reduced-section shank of five steam generator manway bolts attributed to fatigue. The applicant's review of industry operating experience has also indicated incidents of loss of pressure boundary integrity due to leakage of boric acid at bolted joints, SCC of high-strength bolts, and cracking due to fatigue.

3.0.3.3.2 Staff Evaluation

During the AMP audit, the staff confirmed the applicant's claim that the Bolting Integrity Program is consistent with GALL. In addition, for Ginna, the staff determined whether the applicant properly applied the GALL program to its facility. The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program.

3.0.3.3.3 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that this program is consistent with the GALL program. Therefore, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.0.3.4 Boric Acid Corrosion Program

3.0.3.4.1 Summary of Technical Information in the Application

The applicant's Boric Acid Corrosion Control Program is discussed in LRA Section B2.1.6, "Boric Acid Corrosion Control Program." The applicant stated that the program will be consistent with GALL Program XI.M10, "Boric Acid Corrosion." The applicant also stated that the program will be enhanced to address non-RCS systems and components subject to boric acid leakage, including cable connectors, cable trays, and other susceptible structures, systems, and components (SSCs).

This AMP is credited with managing the aging of carbon steel and low-alloy steel structures or components or electrical components on which borated water may leak in the RCS, ESF, SPCS, structures and component supports, and electrical systems. The applicant's program was developed and implemented to meet generic letter (GL) 88-05 "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants," and to monitor the condition of the RCS pressure boundary components for boric acid leakage. The program identifies carbon steel components within the RCS that are susceptible to corrosion from boric acid leakage and provides for visual inspection of adjacent components. The program will be enhanced to account for boric acid corrosion of non-RCS components including cable connectors, cable trays, and other susceptible SSCs.

Ginna has experienced residual heat removal (RHR) heat exchanger stud, and RHR and chemical and volume control system (CVCS) body-to-bonnet bolting degradation as a result of boric acid corrosion caused by boric acid leakage at bolted joints. Degradation was detected by visual examination, and the bolting was replaced. The applicant performed reactor vessel head penetration inspections as identified in NRC Bulletin 2002-01 and found no evidence of leakage.

3.0.3.4.2 Staff Evaluation

Since the applicant indicated that the program did not meet the GALL Boric Acid Program when the LRA was submitted, the staff requested additional information in a letter dated March 21, 2003, regarding the applicant’s program. The applicant responded to these RAIs in a letter dated May 13, 2003, and indicated the program had been revised and was consistent with GALL. The staff confirmed the applicant’s claim of consistency during the AMP audit that was performed for Ginna on June 23–25, 2003. In addition, the staff determined whether the applicant properly applied the GALL program to the facility.

In RAI B2.1.6-1, the staff requested information identifying when the AMP would be consistent with GALL and what changes would be made to the applicant’s Boric Acid Corrosion Control Program for it to be consistent with GALL Section XI.M10. The applicant indicated that as of March 2003 the program had been revised and was now consistent with GALL. The applicant indicated that the primary changes necessary for consistency with GALL resulted in an expansion of the program scope beyond RCS components to include carbon and low-alloy steel components that could be subjected to boric acid leaks. The program originally had been limited to the scope recommended by GL 88-05. Changes also included ensuring boric acid leaks are entered into the corrective action program and, if necessary, technical evaluations are performed for affected components in accordance with the guidance in the EPRI Boric Acid Corrosion Guidebook (EPRI TR-104748) and GL 88-05.

The staff found the applicant’s RAI response acceptable because the applicant has revised the Boric Acid Corrosion Program for consistency with GALL prior to the period of extended operation.

In light of the events at Davis-Besse regarding reactor pressure vessel head degradation, the staff requested additional information regarding the applicant’s operating experience and program changes. In RAI B2.1.6-2, the staff requested that the applicant address the changes that were made to its Boric Acid Corrosion Prevention Program in response to the Davis-Besse reactor vessel head boric acid corrosion event. The applicant responded to this RAI in a letter dated May 13, 2003. The applicant indicated information provided to licensees in NRC Bulletins 2002-01, "Reactor Pressure Vessel Head Degradation and RCS Pressure Boundary Integrity,” and 2002-02, “Reactor Pressure Vessel Head Penetration Nozzle Inspection Programs,” directly contributed to the applicant’s new Boric Acid Corrosion Monitoring Program procedure. Specific changes to the Boric Acid Corrosion Monitoring Program resulting from the Davis-Besse operating experience include the identification of RCS locations containing Alloy 600 and Inconel 82/182 weld materials. Moreover, the control rod penetrations are specifically called out for inspection. Additionally, during leak evaluations any identified boric acid residue will be evaluated to ensure it does not contain rust-like coloring and, when a leak is identified in containment or in an area with enclosed ventilation units, the ventilation units will be evaluated for evidence of boron precipitation.

The staff found the applicant's RAI response acceptable since the applicant expanded the Boric Acid Corrosion Program scope to become consistent with GALL and incorporated lessons learned from Davis-Besse and recent staff generic communications (i.e., identification of locations where leakage could lead to corrosion damage, examination of ventilation units for boron precipitation, and engineering evaluations of potentially affected components).
This additional operating experience supports the staff's determination that the program will provide reasonable assurance that age-related degradation will be managed during the period of extended operation.

The staff confirmed the applicant's claim that the Boric Acid Corrosion Control Program is consistent with GALL during the AMP audit. In addition, for Ginna, the staff determined whether the applicant properly applied the GALL program to its facility. The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program.

3.0.3.4.3 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that this program is consistent with the GALL program. Therefore, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.0.3.5 Closed-Cycle (Component) Cooling Water System Program

3.0.3.5.1 Summary of Technical Information in the Application

The applicant's Closed-Cycle (Component) Cooling Water System AMP is discussed in LRA Section B2.1.9, "Closed-Cycle (Component) Cooling Water." The applicant does not conclude whether the program is or is not consistent with the equivalent GALL Program, XI.M21, "Closed-Cycle Cooling Water System." The applicant acknowledges that there are differences from the GALL program but states that the differences were evaluated and were determined to be minor in terms of assuring proper functionality of system components.

The AMP is credited with managing the aging effects of loss of material due to general corrosion, pitting, and crevice corrosion in ESF and SPCS and loss of material due to general, pitting, and crevice corrosion, and MIC in the auxiliary systems.

The applicant’s program includes preventive measures, such as maintenance of system corrosion inhibitor concentration in accordance with EPRI TR-107396 limits to minimize corrosion and surveillance testing and inspection to monitor the effects of corrosion. Differences do exist between the applicant’s program and that outlined in the GALL Report. In the applicant’s program, the only parameters monitored are pH, corrosion inhibitor concentration, and radioactivity. According to the applicant, plant operating experience indicates there is no value added by monitoring additional parameters. Cooler and heat exchanger temperatures and differential pressures are not monitored, but temperature and pressure are monitored at other locations throughout the system to assure proper functionality. Corrosion coupons are not used in the system based on operating experience which does not show a need. Finally, the applicant does not perform MIC testing in the system because the use of chromated water acts as an effective biocide as well as a corrosion inhibitor.

On the basis of the above discussion, the applicant indicates that its program is capable of assuring proper functionality of system components.

3.0.3.5.2 Staff Evaluation

The applicant’s LRA did not clearly indicate if this program was intended to be consistent with the GALL program; therefore, the staff, in a letter dated March 21, 2003, issued RAI B.2.1.9-1. The RAI focused on requesting the licensee to discuss if the program was consistent with the GALL Report or, if not consistent with GALL, to provide a description of the program relative to the 10 elements of an AMP. The applicant responded to the RAI in a letter dated May 13, 2003, and indicated that the Closed-Cycle Cooling Water Program is consistent with GALL Program XI.M21, with exceptions. The staff confirmed the applicant’s claim of consistency during the AMP audit that was performed June 23–25, 2003. Furthermore, the staff reviewed the program and the deviations with their justifications to determine whether the AMP, with the deviations, remains adequate to manage the aging effects for which it is credited. The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the revised program.

In RAI B.2.1.9-1, the staff requested the applicant to address a subset of RAIs if the applicant concluded the program was consistent with GALL.

The staff requested that the applicant discuss how the program ensures aging effects are identified prior to a loss of function and how the program ensures that heat transfer capabilities are maintained. In response to this portion of RAI B.2.1.9-1, the applicant indicated that the Closed-Cycle (Component) Cooling Water System Surveillance Program employs various methods to ensure that components will continue to perform their intended function. Periodic maintenance activities performed under the Periodic Surveillance and Preventive Maintenance Program provide opportunities for visual inspections of the internal (wetted) and external surfaces of components in the system. Thermal performance testing of selected heat exchangers is used to verify that these components are capable of performing the heat removal function. Monitoring of the component cooling water (CCW) chemistry and maintaining parameters within the specified limits ensures that the system is maintained free of corrosion and biofouling.

The applicant stated that plant-specific operating experience indicates that the CCW system performance has been satisfactory. No evidence of corrosion product buildup or corrosion-induced degradation in CCW piping or components has ever been identified at Ginna Station. Destructive metallurgical examination of a leaking pipe-to-elbow weld performed in 1991 revealed no evidence of corrosion or degradation of the internal surfaces of the pipe and elbow exposed to the CCW environment. The leak was determined to be the result of a large slag inclusion in the weld which was an original fabrication defect. Further confirmation of the effectiveness of CCW chemistry control was obtained during remote visual inspection of the internal surfaces of the carbon steel heat exchanger shell, tubesheet, and tube supports, as well as piping connections, during retubing of both CCW heat exchangers in 1999. All surfaces were clean and in excellent condition.

The staff reviewed the applicant’s response and found it acceptable based on the combined use of the Periodic Surveillance and Preventive Maintenance Program to provide opportunities for visual inspection of internal surfaces, thermal performance testing to ascertain heat transfer capability, and water chemistry to mitigate corrosion and limit fouling. The applicant also described operating experience indicating corrosion issues have been absent, thus supporting acceptability of this response and providing objective evidence that the program will manage aging.

The staff noted the applicant samples for pH, chromates, and radioactivity and requested further discussion supporting why the applicant does not sample for corrosion products, calcium, potassium, refrigerant chemicals, chlorides, or sulfates. In response to this portion of RAI B.2.1.9-1, the applicant indicated that demineralized water is used as makeup water for this system. Therefore, calcium and other mineral deposits, chlorides, and sulfates are not an issue in the system. Chromate is added as potassium dichromate; therefore, sampling for potassium is not necessary. No components with refrigerant chemicals are serviced by the CCW system.

The staff reviewed the applicant’s response and finds that the use of demineralized water alleviates the need to sample chemistry parameters other than pH, chromates, and radioactivity in the closed-cycle cooling water system.

The staff requested that the applicant discuss how the effectiveness of chemistry control in stagnant and low-flow areas is determined for the closed-cycle cooling water system.
In response to this portion of RAI B.2.1.9-1, the applicant indicated that it uses plant operating experience with relief valves located on stagnant system tail pieces. The relief valves are periodically removed, tested, and inspected by the Periodic Surveillance and Preventive Maintenance Program. No evidence of degradation has been identified at these locations.

The staff finds that using relief valves to indicate the performance of chemistry control in stagnant and low-flow areas is acceptable based on the provided operating experience, which identified no evidence of degradation at these locations. The operating experience provides objective evidence that the program will adequately manage aging.

The staff noted the operating experience discussion indicated that due to condensation, external corrosion had affected the surface of some CCW system piping and requested the applicant to discuss how much of the system was affected, how long the system had been in operation, the extent of the ultrasonic testing (UT) which noted no significant wall thinning, and how any wall loss was attributed to internal or external corrosion. In response to this portion of RAI B.2.1.9-1, the applicant indicated the pipe had been in service since original construction and experienced only minor surface rusting. Ultrasonic testing scans performed over several inches of pipe length and around the pipe circumferences were taken to determine the maximum and minimum wall thickness. The applicant indicated that all thickness readings were acceptable and corrective action included insulating approximately 2000 feet of the piping.

The staff finds the applicant’s response providing additional information relative to the operating experience with surface corrosion of portions of the closed-cycle cooling water system acceptable based on the applicant’s further explanation that the corrosion was limited to minor surface rusting. The additional operating experience provides objective evidence that the program will adequately manage aging during the period of extended operation.

3.0.3.5.3 Conclusions

On the basis of its review and audit of the applicant’s program, the staff finds that this program is consistent with the GALL program. Therefore, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.0.3.6 Flow-Accelerated Corrosion Program

3.0.3.6.1 Summary of Technical Information in the Application

The applicant’s Flow-Accelerated Corrosion Program is discussed in LRA Section B2.1.15, “Flow-Accelerated Corrosion.” The applicant stated that the program is consistent with GALL Program XI.M17, “Flow-Accelerated Corrosion,” with no deviations.

This AMP is credited with managing flow-accelerated corrosion (FAC) of components made from carbon or low-alloy steel and exposed to single-phase fluid in feedwater and condensate systems and to two-phase fluid in extraction steam lines, moisture separation reheater, and feedwater heater drain lines.

The applicant stated that the plant has a comprehensive program that addresses FAC control measures in accordance with the EPRI guidelines in Nuclear Safety Analysis Center (NSAC) 20L-R2, “Recommendation for an Effective Flow-Accelerated Corrosion Program.”
The program includes use of the CHECWORKS computer code for predicting wear rates caused by FAC and the procedures for the subsequent inspections and repair or replacement of the damaged components.

3.0.3.6.2 Staff Evaluation

During the AMP audit, the staff confirmed the applicant’s claim that the Flow-Accelerated Corrosion Program is consistent with GALL. In addition, for Ginna, the staff determined whether the applicant properly applied the GALL program to its facility. The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program.

3.0.3.6.3 Conclusions

On the basis of its review and audit of the applicant’s program, the staff finds that this program is consistent with the GALL program. Therefore, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.0.3.7 One-Time Inspection Program

3.0.3.7.1 Summary of Technical Information in the Application

The applicant’s One-Time Inspection Program is described in Section B2.1.21 of the LRA. The LRA states that the program will be consistent with GALL Program XI.M32, “One-Time Inspection.” The LRA states that the program will be used to verify that unacceptable degradation is not occurring, and that in this way it will validate the effectiveness of an existing AMP (usually the Water Chemistry Control Program) or confirm that there is no need to manage potential age-related degradation for the period of extended operation. The LRA lists four items in the scope of this program as follows:

(1) verification of the effectiveness of the Water Chemistry Control Program for managing the effects of aging in stagnant or low-flow portions of piping, or occluded areas of components, exposed to treated water environments

(2) managing cracking due to SCC or cyclic loading due to thermal fatigue in small-bore Class 1 piping less than 4 inches nominal pipe size (NPS) that is directly connected to the reactor coolant system

(3) managing loss of material due to galvanic corrosion on the internal surfaces of piping and components in treated water systems at locations where galvanic couples are present

(4) managing loss of material and/or loss of structural integrity due to selective leaching on the internal surfaces of piping and components made of gray cast iron, bronze, or brass exposed to treated water or raw water environments

The LRA states that the program elements will include (a) determination of appropriate inspection sample size based on materials of construction, environment, plausible aging effects, and operating experience, (b) identification of inspection locations, (c) selection of examination technique, with acceptance criteria, and (d) evaluation of results to determine the need for additional inspections or other corrective actions. The LRA further states that the inspection sample will include locations where the most severe aging effect(s) would be expected to occur, and that inspection methods will include visual (or remote visual), surface or volumetric examination, or other established nondestructive examination (NDE) techniques. The LRA states that the One-Time Inspection Program is a new program and that the scope and techniques that will be employed are consistent with industry practice.

3.0.3.7.2 Staff Evaluation

The GALL Report recommends use of this program to verify the effectiveness of other AMPs and to verify that aging effects are not occurring. During the AMP audit, the staff confirmed the applicant's claim of consistency. The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program. Furthermore, the staff reviewed the applicant's evaluation to determine whether it addressed the additional issues recommended in the GALL Report and confirmed that the AMP would adequately address these issues. Finally, for Ginna, the staff determined whether the applicant properly applied the GALL Report program to its facility.

The staff reviewed the tables in Sections 2 and 3 of the LRA to confirm that the structures and components that credit the One-Time Inspection Program are generally commensurate with the GALL Report. In addition to the four items mentioned in Section 3.0.3.7.1, the staff identified numerous components where the One-Time Inspection Program is used to confirm the absence of significant aging effects. The staff considers these items to be consistent with the GALL program.

The staff also identified that the One-Time Inspection Program is credited for material/environment combinations where it was not clear from the LRA whether aging could be expected, such that periodic inspections would be more appropriate than a one-time inspection. The staff asked the applicant to justify why a one-time inspection is appropriate for (1) change in material properties of neoprene, (2) loss of material of cast iron and carbon steel in raw water, treated water (where the One-Time Inspection Program is the only AMP), and drainage water, and (3) loss of heat transfer of cast iron in raw water. In its responses to the staff's RAIs, dated May 13, May 23, and July 30, 2003, the applicant provided the following justification:

(1) For change in material properties of neoprene, the applicant stated that a one-time inspection is used for internal environments of oil, fuel oil, raw water, and treated water where the temperature remains below 95 °F and the exposure to ionizing radiation remains below 10^6 rads. The applicant stated that below these threshold values, changes in material properties are not expected, and that plant experience reveals no evidence of age-related degradation of neoprene exposed to these environments. Since the environment is not expected to cause significant degradation of neoprene, the staff finds it acceptable to use a one-time inspection.

(2) For loss of material of cast iron in raw and treated water, the applicant stated that plant experience shows that gray cast iron exhibits good resistance to fresh (raw) waters such as Lake Ontario water, that the behavior in drainage water is expected to be the same as in raw water, and that the behavior in treated water is expected to be at least as good as in raw water. Based on the plant operating experience, the staff finds this acceptable.

(3) For loss of material of carbon/low-alloy steel in treated water, the applicant clarified that the One-Time Inspection Program is used for piping, valves, and the reactor makeup water storage tank in the treated water system to verify the effectiveness of the Water Chemistry Program. The applicant also described its operating experience with these components, and the operating experience supports the applicant's conclusion that aging is either not occurring or is occurring very slowly. Based on the operating experience, the staff finds it acceptable to use the One-Time Inspection Program to verify the effectiveness of the Water Chemistry Program in preventing loss of material for these components.

(4) For loss of material of carbon steel in raw water, the applicant clarified that, instead of the One-Time Inspection Program, periodic inspections would be performed under the Periodic Surveillance and Preventive Maintenance Program. The staff considers the use of the Periodic Surveillance and Preventive Maintenance Program (evaluated in Section 3.0.3.8) to be appropriate for this material/environment combination; therefore, the staff finds this acceptable.

(5) For loss of heat transfer of cast iron in raw water, the applicant clarified that the concern was reduction of flow to cast iron outboard bearing oil coolers for the auxiliary feedwater pumps, caused by loss of material, and that plant experience shows that the gray cast iron exhibits good resistance to loss of material in Lake Ontario water. Based on the plant operating experience, the staff finds this acceptable.

The staff also asked for justification for using a one-time ultrasonic inspection, in combination with periodic visual examination of the internal surfaces, for the buried fuel oil storage tanks. In its response, dated May 23, 2003, the applicant described the tank construction and examination history and also clarified that instead of a one-time inspection, the ultrasonic examination would be performed periodically under the Periodic Surveillance and Preventive Maintenance Program. The staff finds that performing an ultrasonic examination on a periodic basis (under the Periodic Surveillance and Preventive Maintenance Program evaluated in Section 3.0.3.8 of this SER) will adequately monitor for degradation of the external surface of the buried fuel oil storage tanks; therefore, the staff finds this acceptable.

The staff also asked for justification for using a one-time inspection for loss of material of a buried carbon steel pipe in the hydrogen detectors and recombiner system. In its response, dated May 23, 2003, the applicant stated that the pipe was originally exposed and was apparently covered with engineered backfill during a plant modification. The applicant stated that the aging management would consist of excavating the pipe to perform the one-time inspection and subsequently including the pipe in the Systems Monitoring Program. Since the Systems Monitoring Program (evaluated in Section 3.0.3.11 of this SER) is effective in managing external corrosion for this material/environment combination, the staff finds this acceptable.

The GALL Report recommends, and the applicant credits, the use of this program to verify the effectiveness of the applicant's Water Chemistry Control Program (B2.1.37, which is evaluated in Section 3.0.3.1 of this SER), for several systems in the RCS, ESF, auxiliary systems, and SPCS groups. The LRA indicates that the One-Time Inspection Program will include stagnant or low-flow portions of piping, or occluded areas of components, exposed to treated water environments. The LRA further states that the program will include (a) determination of appropriate inspection sample size based on materials of construction, environment, plausible aging effects, and operating experience, (b) identification of inspection locations, (c) selection of examination technique with acceptance criteria, and (d) inspection of locations where the most severe aging effect(s) would be expected to occur. These program attributes satisfy the recommendations in the SRP-LR for verifying the effectiveness of a chemistry program; therefore, the staff finds this acceptable.

The GALL Report also recommends the use of this program, in conjunction with the Water Chemistry Control Program, to verify that cracking is not occurring in small-bore, RCS and connected systems piping, where the ASME Code does not require volumetric examination during ISI. The LRA states that the One-Time Inspection Program will be used to manage cracking due to SCC or cyclic loading due to thermal fatigue in small-bore Class 1 piping (less than 4 inches NPS) that is directly connected to the RCS. The LRA also states that volumetric examinations will be performed, since cracking is expected to originate at the internal surface of the pipe. These program attributes satisfy the recommendations in the SRP-LR for small-bore RCS and connected systems piping; therefore, the staff finds this acceptable.

The staff has reviewed the UFSAR Supplement for this program in LRA Section A2.1.15, "One-Time Inspection." In RAI B2.1.21-3, the staff noted that, while the UFSAR description is generally consistent with the program description in the LRA, the UFSAR description did not contain a level of detail commensurate with the SRP-LR. In its responses to the staff's RAIs, dated May 23 and July 30, 2003, the applicant augmented the UFSAR Supplement to provide additional detail related to program attributes and how the program is used to satisfy the further evaluations recommended in the GALL Report. The staff finds that the augmented description of the program is commensurate with the SRP-LR and is acceptable.

3.0.3.7.3 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that this program is consistent with the GALL program. Therefore, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.0.3.8 Periodic Surveillance and Preventive Maintenance Program

3.0.3.8.1 Summary of Technical Information in the Application

The applicant described its Periodic Surveillance and Preventive Maintenance Program in Section B2.1.23 of the LRA. The LRA states that the program is credited for managing aging effects such as loss of material, crack initiation, fouling buildup, and loss of seal for structures and components within the scope of license renewal. The program is also used to verify the effectiveness of other AMPs. The LRA states that the program provides for visual inspection and examination of surfaces of selected equipment items and components, including fasteners, for evidence of defects and age-related degradation such as corrosion, wear, cracking, fouling, etc., on a specified frequency based on operational experience. The LRA states that the program also utilizes leak inspection of piping and components, and replacement or refurbishment of components on a specified frequency. For operating experience, the LRA states that the Periodic Surveillance and Preventive Maintenance Program has been in place since Ginna began operation, that a significant number of corrective actions have been initiated to correct conditions identified by this program, and that this program has proven effective in maintaining the material condition of plant structures and components.

3.0.3.8.2 Staff Evaluation

The Periodic Surveillance and Preventive Maintenance Program is not based on a GALL Report program; therefore, the staff reviewed the program using the guidance in Branch Technical Position RLSB-1 in Appendix A to the SRP-LR (NUREG-1800). The staff's evaluation focused on management of aging effects through incorporation of the 10 elements from RLSB-1 (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 for license renewal are in accordance with the site-controlled Quality Assurance Program. The staff's evaluation of the applicant's Quality Assurance Program is provided separately in Section 3.0.4 of this SER, and the evaluation of the remaining seven elements is provided below. The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program.

The staff notes that "repetitive tasks" in the Periodic Surveillance and Preventive Maintenance Program are used to initiate aging management activities that are performed as part of other AMPs. Those activities are evaluated with the appropriate AMPs and are not discussed in this section of the SER.

Program Scope. The LRA states that the Periodic Surveillance and Preventive Maintenance Program provides for visual inspections and surface examinations of certain piping, equipment, and components in all plant systems within the scope of license renewal. The LRA also states that the program provides for replacement or refurbishment of certain components on a specified frequency.

The staff noticed that the Periodic Surveillance and Preventive Maintenance Program is widely used throughout the RCS, emergency core cooling system (ECCS), auxiliary systems, and SPCS to manage loss of material, cracking, change in material properties, and loss of heat transfer, primarily for internal environments. Several items, such as the inspection of the buried fuel oil storage tanks and the inspection of carbon steel items in raw water, were added to the scope of this program in the applicant's responses to staff RAIs.

In its response to the staff's RAI, by letter dated May 23, 2003, the applicant clarified that the Periodic Surveillance and Preventive Maintenance Program is used for verification of the effectiveness of the Water Chemistry Control Program, and that the inspections performed under the Periodic Surveillance and Preventive Maintenance Program are comparable to those performed under the One-Time Inspection Program. The applicant selected the Periodic Surveillance and Prevention Maintenance Program as the inspection initiating activity when opportunities for inspection due to routine maintenance were identified. Where no such inspection opportunity was presented, the One-Time Inspection Program was credited. In the letter dated June 13, 2003, the applicant also stated that if a component in the scope of license renewal was already included in the Periodic Surveillance and Preventive Maintenance Program, the Periodic Surveillance and Preventive Maintenance Program was credited for aging management. If an established program activity required enhancement to satisfy the aging management requirements, a tracking mechanism was put in place to revise the implementing procedures to include all necessary inspections for all applicable aging effects for each program activity.

The staff finds that the applicant's description of the scope of this program adequately covers the items which credit this program; therefore, the staff finds the scope acceptable.

Preventive Actions. The LRA states that the inspection and testing activities of the Periodic Surveillance and Preventive Maintenance Program are primarily monitoring activities, but the periodic replacement or refurbishment of components may be considered preventive in nature. The staff agrees with this assessment, and does not identify the need for further preventive actions; therefore, the staff finds this acceptable.

Parameters Monitored or Inspected. The LRA states that the Periodic Surveillance and Preventive Maintenance Program provides for visual inspection and examination of surfaces, including interior surfaces, of selected equipment items and components, including fasteners, for evidence of defects and age-related degradation, such as loss of material due to corrosion and wear, cracking, fouling buildup, and leakage, on a specified frequency based on operational experience. The LRA also states that equipment or system operating parameters, such as pressure, flow, and temperature, are monitored by performance tests to detect performance degradation that may be indicative of aging effects. The LRA further states that the current guidelines in operations, maintenance, and surveillance test procedures and plant work orders will be enhanced to provide explicit guidance on detection of applicable aging effects and assessment of degradation. The staff finds that monitoring or inspecting the above parameters is appropriate for managing the aging effects that are covered by this program; therefore, the staff finds the parameters monitored or inspected acceptable.

Detection of Aging Effects. The LRA states that aging effects, such as loss of material due to corrosion and wear, cracking, loss of seal, etc., are detected by visual inspection of surfaces for evidence of leakage, material thinning, accumulation of corrosion products, and debris. The LRA also states that plant procedures will be enhanced to provide explicit guidance on detection of applicable aging effects and assessment of degradation.

The staff noted apparent inconsistencies in the LRA regarding the types of inspections that would be performed under the Periodic Surveillance and Preventive Maintenance Program; therefore, the staff asked for clarification (RAI B2.23-4). By letter dated May 23, 2003, the applicant stated that the Periodic Surveillance and Preventive Maintenance Program provides for visual, surface, and/or volumetric inspections, and surface and/or volumetric examinations are used to supplement visual inspections as deemed necessary by engineering evaluation. The applicant further stated that heat exchangers and coolers are inspected using volumetric techniques such as eddy current testing of tubing, that polymeric seals and gaskets in certain ventilation system components are periodically inspected for evidence of age-related degradation, and that leak inspections of piping and components in selected portions of systems are also performed on a specified frequency. The staff finds the above clarification acceptable. Additional information on the detection of aging effects is provided in the applicant's RAI responses discussed below.

The LRA states that inspection for leakage may be utilized for managing aging effects in selected piping and components. It is the staff's position that actual leakage is indicative of piping or component failure; therefore, the AMP should be aimed at detecting and preventing loss of material so that corrective actions can be taken prior to the occurrence of leakage. In RAI B2.1.23-2, the staff asked the applicant to identify the specific circumstances where leakage inspection is proposed to be utilized for aging management. In its response, dated May 13, 2003, the applicant provided the following response:

> RG&E acknowledges that actual leakage is indicative of some type of degradation. However, In-Service Inspection (ISI) regulations require that leak inspections be performed. The PSPM program implements surveillance activities including ASME Section XI required leakage examinations for borated water systems and other leakage examinations inside and outside of containment. Thus the program must contain reference to leakage inspections even though those inspections may not be directly credited with managing the effects of aging of the SSC being inspected. Moreover, the leak inspections initiated by the PSPM program are an important element of the Boric Acid Corrosion program. The identification of leaks and the evaluation of the consequences of those leaks are the condition where leakage monitoring is an important technique utilized for component aging management. It is important to note that PSPM initiated leakage inspections are just one of several methods used for detecting and monitoring the effects of aging. Other techniques include visual examinations, supplemental surface and volumetric examinations deemed necessary by engineering evaluation, volumetric (eddy current) examinations of heat exchanger tubing, and other periodic volumetric examinations including radiography and ultrasonic testing to verify wall thickness as required by the Open-Cycle Cooling Water System program.

The staff considers the applicant's use of leakage detection to be reasonable and appropriate. The staff also notes that leakage detection is not used as the only aging management for components but is combined with other inspection techniques as detailed in the applicant's response discussed above; therefore, the staff finds this acceptable.

The LRA states that cracking and material thinning will be detected by performing visual inspections and surface examinations. Since cracking and thinning on the interior surfaces (for example, interior surfaces of pipe walls), cannot be detected by such methods, the staff requested the applicant to indicate the methods which will be employed to detect such defects (RAI B2.1.23-1). In its response, dated May 13, 2003, the applicant stated, in part, the following:

> The Periodic Surveillance and Preventive Maintenance program manages aging effects for SSCs within the scope of license renewal. Aging effects such as loss of material due to various corrosion mechanisms and wear are detected by visual examinations of surfaces for evidence of general or localized material thinning, presence of corrosion products, deposit accumulation, etc. Supplemental inspections using other NDE techniques such as surface (e.g., dye penetrant or magnetic particle) and volumetric (e.g., ultrasonic or radiographic) examinations are performed as necessary based on engineering evaluation. Change in material properties of polymeric seals and gaskets is detected by visual examination for evidence of cracking and crazing, evaluation of resilience and indentation recovery, evidence of swelling, tackiness, etc. Degradation of heat exchanger tubing is detected by eddy current testing, which provides the capability of detecting both ID and OD initiated tube-wall degradation such as thinning due to general, pitting and under-deposit (crevice) corrosion, MIC, fretting wear, fouling and cracking.

The staff finds the applicant's response acceptable because the applicant relies on other NDE techniques besides visual inspection for detecting cracking and thinning on interior surfaces.

In its response to the staff's RAI related to the One-Time Inspection Program, dated May 23, 2003, the applicant stated that a periodic ultrasonic examination would be performed under the Periodic Surveillance and Preventive Maintenance Program to monitor for loss of material of the buried fuel oil storage tanks. The staff finds that a periodic ultrasonic examination can effectively detect loss of material on the internal and external surfaces of the tanks; therefore, the staff finds this acceptable.

The staff finds that the above methods for detecting aging are consistent with industry practices and are capable of identifying the applicable aging effects; therefore, the staff finds this acceptable.

Monitoring and Trending. The LRA states that the Periodic Surveillance and Preventive Maintenance Program provides for monitoring and trending of material condition and equipment performance, that the program's activity intervals are established to provide timely detection of degradation, and that the intervals are based on service environment as well as industry and plant-specific operating experience and manufacturer's recommendations. The LRA also states that operations and maintenance procedures specify activities to monitor for early detection of degradation, such as coatings failures, corrosion, cracking, leakage and physical condition, mechanical damage, and loose or missing hardware; that data are documented, trended and evaluated to identify and correct deficiencies; and that intervals may be adjusted as necessary based on inspection results and industry experience.

In its response to the staff's RAIs, dated May 23, 2003, the applicant further stated that if a component in the scope of license renewal was already included in the Periodic Surveillance and Preventive Maintenance Program due to industry or plant-specific operating experience, the Periodic Surveillance and Preventive Maintenance Program was credited for aging management. The periodicity of many surveillance and preventive maintenance activities that were credited for license renewal was initially driven by considerations other than aging. A tracking mechanism was put in place to revise specific instructions in appropriate implementing procedures to include inspections for aging effects for each Periodic Surveillance and Preventive Maintenance Program activity. The program's activity intervals are established to provide timely detection of degradation and take into consideration known aging effects/mechanisms for material/service environment combinations, as well as industry and plant-specific operating experience and manufacturer's recommendations. The results of periodic surveillance inspections and preventive maintenance activities performed on selected equipment items are documented, evaluated, and trended. Based on the results of these aging management activities, inspection frequencies may be adjusted.

As examples, the applicant stated that an internal inspection of a check valve in the CCW system (which has a chemistry-controlled environment such that the effects of aging typically occur slowly) is more likely to be driven by seat/disc/hinge pin wear than by erosion or corrosion of the valve body. For components exposed to raw water environments, the periodicity of inspections is determined by trending data based on wall thickness measurements, corrosion product accumulation, fouling/biofouling buildup, etc. For heat exchangers, inspection frequencies are established by trending of tube wall degradation data. The applicant concluded that these trending evaluations have been effective in establishing frequencies which ensure that the effects of aging are managed such that intended functions of SSCs are maintained and will be maintained during the period of extended operation.

For equipment that is subject to periodic replacement or refurbishment, the LRA was not clear as to how the applicant verified that the equipment can perform its intended function at the time it is replaced or refurbished. The staff asked about inspections of this equipment and the basis for the replacement or refurbishment period. In its response, dated June 13, 2003, the applicant indicated that inspections are performed on the equipment after it is removed from service, and the inspection results are used in establishing replacement frequencies, such that the equipment can perform its intended function at the time of replacement or refurbishment. The staff finds that it is appropriate to use the inspection results to set the frequency of replacement/refurbishment; therefore, the staff finds this acceptable.

The applicant stated that the data from the Periodic Surveillance and Preventive Maintenance Program activities will be monitored and trended, and the intervals will be adjusted to ensure the timely identification of aging degradation. Adjusting the intervals based on the data provides reasonable assurance that the appropriate intervals are selected; therefore, the staff finds this acceptable.

Acceptance Criteria. The LRA states that operations, maintenance, and surveillance procedures, and specific task instructions will be enhanced to include explicit instructions for detection of aging effects and definition of acceptance criteria. In its response to RAI B2.1.23-7, dated May 23, 2003, the applicant stated the following:

> Explicit guidance for detection of aging effects will be incorporated into all appropriate plant procedures that implement the Periodic Surveillance and Preventive Maintenance program for aging management purposes during the period of extended operation. This guidance will be developed using published technical reference and industry source material. Acceptance criteria for any degraded condition that is detected during inspections will be established by engineering evaluation of the degraded condition in accordance with the Ginna Station Corrective Action program. This evaluation will address the need for additional nondestructive inspections, changes inspection frequency, as well as design Code requirements and margins.

The acceptance criteria will be established by engineering evaluation and will include design code requirements and margins; therefore, the staff finds this acceptable.

Operating Experience. The LRA states that Periodic Surveillance and Preventive Maintenance Program activities have been in place since Ginna began operation. The applicant's review of plant-specific operating experience reveals that significant numbers of corrective actions have been generated as a result; therefore, the applicant concludes that the Periodic Surveillance and Preventive Maintenance Program activities have proven to be effective in maintaining the material condition of the structures and components and detecting unsatisfactory or degraded conditions. The staff concurs with the applicant's assessment that the operating experience supports the conclusion that the Periodic Surveillance and Preventive Maintenance Program will provide effective aging management during the extended period of operation.

3.0.3.8.3 Conclusions

On the basis of its review of the applicant's program, the staff finds that the program adequately addresses the 10 program elements defined in Branch Technical Position RLSB-1 in Appendix A.1 to the SRP-LR, and that the program will adequately manage the aging effects for which it is credited so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 50.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.0.3.9 Selective Leaching of Materials

3.0.3.9.1 Summary of Technical Information in the Application

The applicant's Selective Leaching Program is discussed in LRA Section B2.1.29, "Selective Leaching of Materials Program." The applicant stated that the program is consistent with GALL Program XI.M33, "Selective Leaching of Materials," with the exception that the applicant will not be performing hardness testing as part of its inspection program. The applicant stated that it will assess the feasibility of performing hardness tests and the value of hardness test data on a component-specific basis.

This AMP is credited with managing aging in selective materials in the ESF and auxiliary systems.

The applicant performed visual inspections under the Periodic Surveillance and Preventive Maintenance Program on those potentially susceptible components which have a routine preventive maintenance activity. One-time inspections are performed on components that do not have a specified routine preventive maintenance activity. The Periodic Surveillance and Preventive Maintenance Program and the One-Time Inspection Program are discussed in detail in Sections B2.1.23 and B2.1.21, respectively, of the LRA. Any significant indications or relevant conditions of degradation discovered with these two programs will be evaluated in accordance with the Ginna Corrective Action Program. Corrective actions are implemented in accordance with Ginna "Quality Assurance Program for Station Operation" (ND-QAP).
The ND-QAP meets the requirements of 10 CFR 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." Provisions for timely evaluation and implementation of required corrective actions, including root cause determinations and prevention of recurrence, are also included as part of the Ginna corrective actions.

In its LRA, the applicant concluded that the Selective Leaching of Materials Program ensures that the selective leaching of materials will be adequately managed.

3.0.3.9.2 Staff Evaluation

As stated in LRA Section B2.1.29, the applicant has removed the hardness test measurement from its inspection program. The applicant stated that assessments will be made on the feasibility of performing hardness tests and the value of hardness test data on a component-specific basis. The staff submitted RAI B2.1.29-1 to the applicant requesting the following clarifications.

The Selective Leaching Program in GALL identifies hardness measurements in addition to visual inspections as a method for determining whether there is a degradation of material on select components due to selective leaching. Hardness test measurements are helpful in evaluating degradation of material in a component due to leaching, where visual inspections may be ineffective. The applicant identified that an assessment of the feasibility of performing hardness tests and the value of hardness data is made on a component-specific basis. Therefore, the staff requested that the applicant explain the deviation from hardness testing and describe how the applicant will determine if selective leaching is occurring without taking hardness measurements. Additionally, the staff requested that the applicant provide detailed information concerning the assessment of the need for a hardness evaluation, components that will be assessed, and how the hardness testing will be performed.

The applicant responded to RAI B2.1.29-1 by stating that hardness testing on components susceptible to selective leaching may be appropriate if the component configuration and geometry allows. Tubing and components with complex internal geometries do not provide adequate physical access to internal surfaces requiring examinations to allow accurate measurements to be made.

The applicant stated that gray cast iron at Ginna would be inspected for graphitic corrosion. This type of corrosion creates a soft, spongy, porous mass consisting of graphite flakes and corrosion products of iron. It is a dark porous mass, brown/black in color which is readily distinguishable visually from the surrounding sound gray iron material after the surface is properly cleaned and prepared by removing surface deposits and debris. The applicant stated that probing the surface of the gray cast iron with a sharp object readily identifies soft, spongy areas which have undergone graphitic corrosion. The applicant concluded that years of experience examining buried gray cast iron gas pipe at RG&E has confirmed that detection of graphitic corrosion may be effectively performed by these methods. The applicant stated that the components that will be examined for potential degradation due to selective leaching are the channel heads for the “A” and “B” emergency diesel generator (EDG) jacket water coolers and lube oil coolers. These coolers have been in service since plant startup and should represent the most severe service conditions for gray cast iron components exposed to raw water. The applicant stated that the channel heads will be cleaned, examined visually, and assessed for the feasibility of performing hardness tests prior to the end of the current license period. If it is determined that hardness tests can be performed, the tests will be made using an Equotip dynamic hardness tester.

The applicant also stated that admiralty brass tubes in the “A” and “B” CCW heat exchangers, and the “A” and “B” EDG jacket water coolers and lube oil coolers will be examined for susceptibility to selective leaching. The licensee stated that the tubing in these heat exchangers is inspected periodically by eddy current testing. The applicant stated that eddy current testing has been effective in detecting loss of material and changes in material permeability caused by the selective leaching process. Destructive metallurgical evaluations of admiralty brass tubes pulled from these units to characterize eddy current test indications have verified evidence of the selective leaching mechanism, such as pits. Therefore, the applicant concluded that the eddy current testing presently performed on these heat exchangers is adequate for detection of tube wall degradation due to selective leaching and no other NDEs, including hardness testing, are required.

During the AMP audit which was conducted at Ginna on June 24 and 25, 2003, the staff confirmed the applicant's claim of consistency. Furthermore, the staff reviewed the deviation and its justification to determine whether the AMP with the deviation remains adequate to manage the selective leaching of materials for which it is credited, and also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the revised program. Based upon the review of information provided by the licensee, and the results of the staff AMP audit, the staff concludes that the applicant has properly applied the GALL AMP XI.M33 to its facility.

3.0.3.9.3 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that this program is consistent with the GALL program. Therefore, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.0.3.10 Structures Monitoring Program

3.0.3.10.1 Summary of Technical Information in the Application

The applicant described its Structures Monitoring Program in Section B2.1.32 of the LRA. The LRA states that this program is consistent with GALL Programs XI.S5, "Masonry Wall Program," XI.S6, "Structures Monitoring Program," and XI.S7, "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants." The applicant credits this program with aging management of civil structures and components within the scope of license renewal. The LRA also states that enhancements will be made to include additional structural components consistent with the scope of the three GALL programs identified above.

Under "Operating Experience," the LRA states that the Structures Monitoring Program requirements have been developed and documented since 1995. However, plant inspections and maintenance of specific structures within the program have been ongoing since initial operation. The LRA further states that structures such as buildings, supports, intakes, canals, etc., including roofs, block/masonry walls, liners, steel, etc. have been maintained periodically to ensure their intended function and have been upgraded consistent with regulatory requirements and industry experience.

In the LRA, the applicant concludes that the Structures Monitoring Program provides reasonable assurance that the aging effects will be managed such that the components within the scope of the program will continue to perform their intended functions consistent with the CLB for the period of extended operation. In LRA Section B2.1.32, “Structures Monitoring Program,” the applicant described its program to manage the aging of civil structures and components within the scope of license renewal. The LRA states that this program is consistent with GALL Program XI.S5, “Masonry Wall Program,” XI.S6, “Structures Monitoring Program,” and XI.S7, “RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants.”

3.0.3.10.2 Staff Evaluation

During the AMP audit, the staff confirmed the applicant’s claim that the Structures Monitoring Program is consistent with GALL. In addition, for Ginna, the staff determined whether the applicant properly applied the GALL program to its facility. The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program.

3.0.3.10.3 Conclusions

On the basis of its review and audit of the applicant’s program, the staff finds that this program is consistent with the GALL program. Therefore, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.0.3.11 Systems Monitoring Program

3.0.3.11.1 Summary of Technical Information in the Application

The applicant described its Systems Monitoring Program in Section B2.1.33 of the LRA. The Systems Monitoring Program is credited for aging management of selected components in the various plant systems at Ginna. The Systems Monitoring Program is credited for managing aging effects such as loss of material, cracking, and fouling buildup for normally accessible, external surfaces of piping, tanks, and other components and equipment within the scope of license renewal. These aging effects are managed through visual inspection and monitoring of external surfaces for leakage and evidence of material degradation, such as corrosion, cracking, degradation of coatings, sealants and caulking, deformation, and debris and corrosion product buildup. The program is based on scheduled system walkdowns, health reports, and performance monitoring and trending analysis. The program is credited for managing the aging of structures and components in the RCS, ESF, auxiliary systems, SPCS, and structures system groups.

The LRA states that the program is based on guidance developed to implement 10 CFR 50.65 (the Maintenance Rule). This guidance has been in place since the mid-1990s and has resulted in a significant number of corrective actions, demonstrating its effectiveness. This guidance will be enhanced to include (1) visual inspection acceptance criteria that consider the design margins, (2) additional guidance on the evaluation of protective coatings, and (3) additional systems/components, consistent with the scope of license renewal, related to a future revision to the appropriate plant procedures.

3.0.3.11.2 Staff Evaluation

The Systems Monitoring Program is not based on a GALL Report program; therefore, the staff reviewed the program using the guidance in Branch Technical Position RLSB-1 in Appendix A to the SRP-LR. The staff's evaluation focused on management of aging effects through incorporation of the 10 elements from RLSB-1 (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 for license renewal are in accordance with the site-controlled Quality Assurance Program. The staff's evaluation of the applicant's Quality Assurance Program is provided separately in Section 3.0.4 of this SER, and the evaluation of the remaining seven elements is provided below. The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program.

<u>Program Scope</u>. The LRA states that the program includes the external portions of systems, components, and equipment which are designated as Maintenance Rule systems and are within the scope of license renewal. The LRA states that the program covers corrosion; cracking; degradation of coatings, sealants, and caulking; deformation; and a debris and corrosion product buildup. The staff finds this acceptable because it is consistent with the AMR items that credit this program.

<u>Preventive Actions</u>. The LRA states that systems monitoring is primarily a condition monitoring program and, thus, there are no preventive actions. The staff concurs with this assessment and does not identify the need for any preventive actions associated with this program.

<u>Parameters Monitored or Inspected</u>. The LRA states that the surface conditions of system piping and components, including visible portions of insulated components, equipment, supports and closure bolting, are monitored through periodic visual examinations for evidence

of leakage, corrosion, cracking, coating degradation, deformation, change in material properties of flexible connections and sealants, fouling, and corrosion product buildup. The staff finds that periodically monitoring these parameters will adequately detect the aging effects covered by this program. Therefore, the staff finds this acceptable.

Detection of Aging Effects. The LRA states that this program relies on visual inspections during walkdowns as the primary means for detection and quantification of aging effects. Accessible portions of the systems are walked down once per quarter, and the entire system is inspected once per operating cycle. The staff finds that visual inspections, conducted during routine system walkdowns, are capable of detecting the aging effects applicable to this program.

Monitoring and Trending. The LRA states that the data from inspections are documented, trended, and evaluated. The LRA also states that the frequency of inspections may be adjusted as necessary based on inspection results and industry experience. The staff finds that the overall monitoring and trending proposed by the applicant are acceptable because they will effectively manage the applicable aging effects.

Acceptance Criteria. The LRA states that the program administrative procedures will be enhanced to include visual inspection acceptance criteria, and that acceptance criteria for external corrosion will consider the design margin of the component being inspected. The staff notes that this program covers a wide variety of components, including metal expansion joints and pump bodies, that may have a wide range of design margin with respect to allowable corrosion. The staff requested additional information related to the acceptance criteria for the visual inspections. In its response, dated May 23, 2003, the applicant stated that the acceptance criteria will be established by an engineering evaluation which will address design code requirements and margins, as well as the need for additional nondestructive inspections. The staff finds that the use of engineering evaluations, using additional inspections and design requirements and margins, as applicable, is appropriate for evaluating the inspection results; therefore, the staff finds this acceptable.

Operating Experience. The LRA states that the systems monitoring inspection requirements have been in place since the mid-1990s in support of the Maintenance Rule and have resulted in a significant number of corrective actions. The LRA also states that the program will be continually reassessed and upgraded based on industry and plant-specific operating experience. The applicant concluded that the systems monitoring inspection requirements have proven to be effective in maintaining the material condition of plant systems. The staff finds that the applicant's operating experience supports the conclusion that the program will adequately manage the aging effects in the structures and components that credit this program.

3.0.3.11.3 Conclusions

On the basis of its review of the applicant's program, the staff finds that the Systems Monitoring Program adequately addresses the 10 program elements identified in Appendix A to the SRP-LR, and that the program will adequately manage the aging effects for which it is credited so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 50.21(a)(3). The staff also reviewed the UFSAR

Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.0.3.12 Existing and GALL Aging Management Programs Not Credited for License Renewal

The following programs are described in the LRA, but no credit was taken for managing or monitoring aging effects during the extended period of operation.

3.0.3.12.1 Thermal Aging and Neutron Embrittlement of Austenitic Stainless Steel Program

In LRA Appendix B, Section B2.1.35, the applicant provided a brief summary of its Thermal Aging and Neutron Embrittlement of Austenitic Stainless Steel Program, which is an existing program at Ginna. However, the applicant did not credit this AMP for managing or monitoring aging effects for SSCs within the scope of license renewal and subject to an AMR. Therefore, the staff did not evaluate this program for license renewal.

3.0.3.12.2 Buried Piping and Tank Surveillance Program

3.0.3.12.2.1 <u>Summary of Technical Information in the Application</u>. The applicant describes its AMP for buried piping and tank surveillance in Section B2.1.8 of the LRA. This program, as described in NUREG-1801 (GALL), recommends the use of National Association of Corrosion Engineers (NACE) standards RP-0285-95 and RP-0169-96 for surveillance and mitigating the corrosion of the external surface of buried carbon steel piping and tanks. The applicant stated that it does not employ these standards or credit the surveillance and preventive measure referenced in these standards as an AMP. Instead, the applicant relies on the following 10 programs in maintaining the intended functions of buried carbon steel piping and tanks:

(1) ASME Section XI, Subsections IWB, IWC, IWD, Inservice Inspection
(2) Water Chemistry Control
(3) Open-Cycle Cooling (Service) Water System
(4) Fire Water System
(5) Fuel Oil Chemistry
(6) One-Time Inspection
(7) Buried Piping and Tanks Inspection
(8) Structures Monitoring Program
(9) Periodic Surveillance and Preventive Maintenance
(10) Systems Monitoring

3.0.3.12.2.2 <u>Staff Evaluation</u>. The applicant does not credit this program for aging management of the buried piping and tanks. This is acceptable because, in accordance with the guidance in the GALL Report, the applicant only needs to implement either the Buried Piping and Tanks Surveillance Program or the Buried Piping and Tanks Inspection Program for aging management of buried piping and tanks. Since the applicant has implemented the Buried Piping and Tanks Inspection Program (see Section 3.3.2.3.1), the staff agrees with the applicant that this program is not needed to manage the aging effects of buried piping and tanks.

3.0.3.12.2.3 Conclusions. Based on the fact that the applicant has implemented the Buried Piping and Tanks Inspection Program to manage the aging effects on buried piping and tanks, the staff concludes that the Buried Piping and Tanks Surveillance Program is not needed to manage the aging effects on buried piping and tanks.

3.0.3.12.3 Compressed Air Monitoring

In LRA Appendix B, Section B2.1.10, the applicant provided a brief summary of its Compressed Air Monitoring Program, which is an existing program at Ginna. However, the applicant did not credit this AMP for managing or monitoring aging effects for SSCs within the scope of license renewal and subject to an AMR. Therefore, the staff did not evaluate this program for license renewal.

3.0.3.12.4 Inaccessible Medium-Voltage Cables Not Subject to Environmental Qualification

In LRA Appendix B, Section B2.1.17, the applicant provided a brief summary of its Inaccessible Medium-Voltage Cables Not Subject to Environmental Qualification Program, which is an existing program at Ginna. However, the applicant did not credit this AMP for managing or monitoring aging effects for SSCs within the scope of license renewal and subject to an AMR. Therefore, the staff did not evaluate this program for license renewal.

3.0.3.12.5 Loose Parts Monitoring

In LRA Appendix B, Section B2.1.19, the applicant provided a brief summary of its Loose Parts Monitoring Program, which is an existing program at Ginna. However, the applicant did not credit this AMP for managing or monitoring aging effects for SSCs within the scope of license renewal and subject to an AMR. Therefore, the staff did not evaluate this program for license renewal.

3.0.3.12.6 Neutron Noise Monitoring

In LRA Appendix B, Section B2.1.20, the applicant provided a brief summary of its Neutron Noise Monitoring Program, which is an existing program at Ginna. However, the applicant did not credit this AMP for managing or monitoring aging effects for SSCs within the scope of license renewal and subject to an AMR. Therefore, the staff did not evaluate this program for license renewal.

3.0.3.12.7 Protective Coatings Monitoring and Maintenance

In LRA Appendix B, Section B2.1.24, the applicant provided a brief summary of its Protective Coatings Monitoring and Maintenance Program, which is an existing program at Ginna. However, the applicant did not credit this AMP for managing or monitoring aging effects for SSCs within the scope of license renewal and subject to an AMR. Therefore, the staff did not review the program for consistency with GALL Section XI.S8 or for adequacy as an AMP.

Although the applicant is not crediting the program as an AMP, the applicant did discuss the 10 elements of an AMP as they relate to the coatings program. It appeared to the staff that this was intended to demonstrate compliance with the resolution of generic safety issue GSI-191 (GSI-191 discusses the clogging of containment emergency sumps and is an open generic safety issue). In order to clarify the applicant's intent in this section of the LRA, the staff submitted RAI B2.1.24-1 requesting the applicant to clarify the intent of providing a discussion on the Protective Coatings Monitoring and Maintenance Program and resolution of GSI-191. The applicant reiterated that the Protective Coatings Monitoring and Maintenance Program is not credited as a license renewal AMP. Further, the applicant indicated that the program's intent and discussion were not intended to demonstrate compliance with the resolution of the GSI which will occur within the CLB.

3.0.3.13 Evaluation Findings

The staff has reviewed the common AMPs in Appendix B to the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that these AMPs will effectively manage aging in the structures and components for which these AMPs are credited so that these components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3). In addition, the staff has reviewed the UFSAR Supplements for these AMPs and concludes that the UFSAR Supplements provide an acceptable description of the programs and activities for managing the effects of aging of the components for which the AMPs are credited, as required by 10 CFR 54.21(d).

3.0.4 R.E. Ginna Quality Assurance Program Attributes Integral to Aging Management Programs

The NRC staff reviewed Appendix B to the LRA, "Aging Management Activities," in accordance with the requirements of 10 CFR 54.21(a)(3) and 10 CFR 54.21(d). A 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. The staff has evaluated the adequacy of certain aspects of the applicant's programs to manage the effects of aging, with particular attention to the three quality assurance program attributes of corrective action, confirmation process, and administrative controls.

3.0.4.1 Summary of Technical Information in the Application

Section 3.0, "Aging Management Review Results," of the LRA, provides an AMR summary for structures and components, or commodity groups, determined during the scoping and screening process to be subject to an AMR. Appendix B, Section B1.0, "Appendix B—Introduction," and Section B2.0, "AMP," of the LRA, provide the AMP descriptions for each program credited for managing aging effects based upon the AMR results provided in Sections 3.2 through 3.7 of the LRA. The applicant stated that the existing Quality Assurance Program implements the requirements of 10 CFR 50, Appendix B, and is consistent with the summary in Appendix A.2 to NUREG-1800. The applicant further stated that the Quality Assurance Program includes the elements of corrective action, confirmation process, and administrative control, and would be applicable to safety-related and nonsafety-related SSCs that were subject to an AMR during the period of extended operation. The AMPs identified as existing or new in Appendix B, Sections B1.3 and B2.0, to the LRA, provide descriptions of the specific attributes of corrective action, confirmation process, and administrative control. A correlation of NUREG-1801 versus Ginna programs credited with aging management is provided in Appendix B, Table B2.0-1, to the LRA.

3.0.4.2 Staff Evaluation

Pursuant to 10 CFR 54.21(a)(3), a license renewal applicant is required to demonstrate that the effects of aging on structures and components subject to an AMR will be adequately managed so that their intended functions will be maintained consistent with the CLB for the period of extended operation. Branch Technical Position RLSB-1, "Aging Management Review—Generic," in NUREG-1800 describes 10 attributes of an acceptable AMP. Of these 10 attributes, 3 are associated with the quality assurance activities of corrective action, confirmation processes, and administrative controls. Table A.1-1, "Elements of an AMP for License Renewal," of Branch Technical Position RLSB-1 provides the following description of these quality attributes:

- Corrective actions, including root cause determination and prevention of recurrence, should be timely.
- The confirmation process should ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective.
- Administrative controls should provide a formal review and approval process.

Branch Technical Position IQMB-1, "Quality Assurance for AMPs," in NUREG-1800 noted that those aspects of the AMP that affect the quality of safety-related SSCs are subject to the QA requirements of Appendix B to 10 CFR Part 50. Additionally, for nonsafety-related structures and components subject to an AMR, the applicant may use the existing Appendix B Quality Assurance Program to address the elements of corrective actions, the confirmation process, and administrative controls.

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 action, confirmation process, and administrative control. These three attributes of the Quality Assurance Program are used by all of the applicant's AMPs. During the staff's audit of the Ginna scoping and screening methodology, the staff reviewed the applicant's programs described in Appendix A, "Updated Final Safety Analysis Report (UFSAR) Supplement," and Appendix B, "Aging Management Activities," to assure that the aging management activities were consistent with the staff's guidance described in Section A.2, "Quality Assurance for AMP," and Branch Technical Position IQMB-1, regarding quality assurance (QA) of the SRP-LR.

Based on the staff's evaluation, the descriptions and applicability of the AMPs and their associated attributes to all safety-related and nonsafety-related structures and components provided in Appendix A and Appendix B to the LRA are consistent with the staff's position regarding QA for aging management. However, the applicant did not sufficiently describe the use of the Quality Assurance Program and its associated attributes (corrective action, confirmation process, and document control) in the discussions provided for the existing AMPs consistent with those descriptions provided for new programs.

In a letter dated March 21, 2003, the staff submitted RAI 2.1-6 to the applicant which requested that the applicant revise or supplement the descriptions in Appendix A and B to the LRA to include a description of the Quality Assurance Program attributes, including references to pertinent implementing guidance as necessary, which are credited for existing programs. In a letter dated May 23, 2003, the applicant provided a response to the RAI which stated that the applicability of the Ginna Quality Assurance Program applies equally to existing programs as to new programs being developed for license renewal. The applicant also stated that the Ginna Quality Assurance Program to the AMP attributes of corrective action, confirmation process, and administrative control can be made relevant to all of the programs credited to manage aging effects for in-scope SSCs.

Corrective actions are implemented at Ginna in accordance with the requirements of 10 CFR 50, Appendix B, and American National Standards Institute (ANSI) N18.7-1976, as committed to in Chapter 17 of the Ginna UFSAR, as described in ND-QAP, "Quality Assurance Program." Provisions for timely evaluation of adverse conditions and implementation of any corrective actions required, including root cause determinations and prevention of recurrence where appropriate, are included in the Corrective Action Program. Corrective actions are implemented through the initiation of an action report in accordance with Ginna procedure IP-CAP-1, "Abnormal Condition Tracking Initiation or Notification (Action) Report," and equipment deficiencies are corrected through the initiation of a work order in accordance with Ginna procedure A-1603.2, "Work Order Initiation."

The applicant stated that with respect to the confirmation process, it is part of the Corrective Action Program and that aging management activities required by this program would also reveal any unsatisfactory condition due to ineffective corrective action. Ginna procedure IP-CAP-1 includes provisions for tracking, coordinating, monitoring, reviewing, verifying, validating, and approving corrective actions, to ensure that effective corrective actions are taken. Potentially adverse trends are also monitored through the action report process. The existence of an adverse trend due to recurring or repetitive adverse conditions will result in the initiation of an action report. Ginna procedure A-1603.6, “Post-Maintenance/Modification Testing,” includes provisions for verifying the completion and effectiveness of corrective actions for equipment deficiencies. The procedure also provides guidance for the selection and documentation of post-maintenance or operability tests, provides guidelines to ensure equipment will perform its intended function prior to return to service, and provides guidelines to ensure the original equipment deficiency is corrected and a new deficiency has not been created.

For administrative control, the applicant stated that the implementing documents are subject to administrative controls, including a formal review and approval process, are implemented in accordance with the requirements of 10 CFR 50, Appendix B, and ANSI N18.7-1976, as committed to in Chapter 17 of the Ginna Station UFSAR, and that various procedures provide the required controls including a formal review and approval process for procedures and other forms of administrative control documents. Ginna procedures ND-PRO, “Procedures, Instructions and Guidelines,” and IP-PRO-3, “Procedure Control,” provide guidance on procedures and other administrative control documents. Procedure IP-PRO-3 provides guidance on procedural hierarchy and classification, content and format, and preparation, revision, review, and approval of nuclear directives and all nuclear operating group procedures. Procedure IP-PRO-4, “Procedure Adherence Requirements,” establishes procedure usage and adherence requirements. Procedure IP-RDM-3, “Ginna Records,” delineates the system for review, submittal, receipt, processing, retrieval, and disposition of Ginna records to meet, as a minimum, the Quality Assurance Program for Station Operation.

Based on the information provided in the LRA, as supplemented by the applicant’s response to the staff’s RAI dated March 21, 2003, the staff has determined that for all AMPs credited for license renewal, the applicant has provided a sufficient description of the Quality Assurance Program attributes and activities for managing the effects of aging that is consistent with the staff’s review guidance in NUREG-1800, Section A.2, “Quality Assurance Program for Aging Management Programs,” and Branch Technical Position IQMB-1, regarding QA.

3.0.4.3 Conclusions

Based on the staff’s review of the applicant’s LRA descriptions and supplemental responses to the request for information regarding the AMP QA attributes credited for license renewal, and the results of the staff’s audit of the scoping and screening methodology, the staff finds that the QA attributes described for all AMPs credited for license renewal are consistent with the requirements of 10 CFR 54.21(a)(3) and 10 CFR 54.21(d) and, therefore, are acceptable.

3.1 <u>Reactor Coolant Systems</u>

This section addresses the aging management of the components of the RCS group. The systems that make up the RCS group are described in the SER sections listed below:

- reactor coolant (2.3.1.1)
- reactor vessel (2.3.1.2)

- reactor vessel internals (2.3.1.3)
- pressurizer (2.3.1.4)
- steam generators (2.3.1.5)
- reactor coolant (non-Class 1) (2.3.1.6)

As discussed in Section 3.0.1 of this SER, the components in each of these reactor systems are included in one of two LRA tables. Table 3.2-1 of the LRA consists of reactor system components that are evaluated in the GALL Report, and LRA Table 3.2-2 consists of reactor system components that are not evaluated in the GALL Report.

3.1.1 Summary of Technical Information in the Application

In LRA Section 3.2, the applicant described its AMRs for the RCS at Ginna.

The description of the systems that comprise the reactor systems group can be found in LRA Section 2.3.1.

The passive, long-lived components in these systems that are subject to an AMR are identified in LRA Tables 2.3.1-1, 2.3.1-2, 2.3.1-3, 2.3.1-4, 2.3.1-5, and 2.3.1-6.

The applicant's AMRs included an evaluation of plant-specific and industry operating experience. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify aging effects that require management. These reviews concluded that the aging effects requiring management based on Ginna operating experience were consistent with aging effects identified in GALL.

The applicant's review of industry operating experience included a review of operating experience through 2002. The results of this review concluded that aging effects requiring management based on industry operating experience were consistent with aging effects identified in GALL.

The applicant's ongoing review of plant-specific and industry-wide operating experience is conducted in accordance with the Ginna Operating Experience Program.

3.1.2 Staff Evaluation

The staff reviewed LRA Section 3.2 to determine whether the applicant has provided sufficient information to demonstrate that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the period of extended operation, in accordance with the requirements of 10 CFR 54.21(a)(3), for the RCS components that are determined to be within the scope of license renewal and subject to an AMR.

The applicant referenced the GALL Report in its LRA. The staff has previously evaluated the adequacy of the aging management of reactor system components for license renewal as documented in the GALL Report. Thus, the staff did not repeat its review of the matters described in the GALL Report, except to ensure that the material presented in the LRA was applicable and to verify that the applicant had identified the appropriate programs as described and evaluated in the GALL Report. The staff evaluated those aging management issues recommended for further evaluation in the GALL Report. The staff also reviewed aging management information submitted by the applicant that was different from that in the GALL Report or was not addressed in the GALL Report. Finally, the staff reviewed the UFSAR Supplement to ensure that it provided an adequate description of the programs credited with managing aging for the reactor system components.

Table 3.1-1 below provides a summary of the staff's evaluation of components, aging effects/mechanisms, and AMPs listed in LRA Section 3.2 that are addressed in the GALL Report.

Table 3.1-1 Staff Evaluation Table for Ginna Reactor System Components in the GALL Report

Component Group	Aging Effect/Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Reactor coolant pressure boundary components	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	TLAA	Consistent with GALL. GALL recommends further evaluation (see Section 3.1.2.2.1 below)
Steam generator shell assembly	Loss of material due to pitting and crevice corrosion	Inservice Inspection; Water Chemistry	Water Chemistry (B2.1.37); ASME Section XI, Subsections IWB, IWC, & IWD Inservice Inspection (B2.1.2); and Steam Generator Integrity (B2.1.31) Programs	Consistent with GALL. GALL recommends further evaluation (see Section 3.1.2.2.2 below)
Isolation condenser	Loss of material due to general, pitting, and crevice corrosion	Inservice Inspection; Water Chemistry	Not applicable since Ginna is a PWR	BWR—Not applicable since Ginna is a PWR
Pressure vessel ferritic materials that have a neutron fluence greater than 10^{17} n/cm^2 (E>1 MeV)	Loss of fracture toughness due to neutron irradiation embrittlement	TLAA, evaluated in accordance with Appendix G to 10 CFR 50 and RG 1.99	TLAA	Consistent with GALL. GALL recommends further evaluation (see Section 3.1.2.2.3 below)
Reactor vessel beltline shell and welds	Loss of fracture toughness due to neutron irradiation embrittlement	Reactor Vessel Surveillance	Reactor Vessel Surveillance Program (B1.1.28)	Consistent with GALL. GALL recommends further evaluation (see Section 3.1.2.2.3 below)
Westinghouse and B&W baffle/former bolts	Loss of fracture toughness due to neutron irradiation embrittlement and void swelling	Plant specific	ASME Section XI, Subsections IWB, IWC, & IWD Inservice Inspection (B2.1.2); and Reactor Vessel Internals (B2.1.27) Programs	Consistent with GALL. GALL recommends further evaluation (see Section 3.1.2.2.3 below)

Component Group	Aging Effect/Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Small-bore reactor coolant system and connected systems piping	Crack initiation and growth due to SCC, IGSCC, and thermal and mechanical loading	Inservice Inspection; Water Chemistry; One-Time Inspection	Water Chemistry (B2.1.37); ASME Section XI, Subsections IWB, IWC, & IWD Inservice Inspection (B2.1.2); and One-Time Inspection (B2.1.21) Programs	Consistent with GALL. GALL recommends further evaluation (see Section 3.1.2.2.4 below)
Jet pump sensing line and reactor vessel flange leak detection line	Crack initiation and growth due to SCC, IGSCC, or cyclic loading	Plant specific	Water Chemistry (B2.1.37) and One-Time Inspection (B2.1.21) Programs	GALL recommends further evaluation of the reactor vessel flange leak detection line (see Section 3.1.2.2.4 below)
Isolation condenser	Crack initiation and growth due to SCC or cyclic loading	Inservice Inspection; Water Chemistry	Not applicable since Ginna is a PWR	BWR—Not applicable since Ginna is a PWR
Vessel shell	Crack growth due to cyclic loading	TLAA	TLAA—See SER Section 4.3	Consistent with GALL. GALL recommends further evaluation (see Section 3.1.2.2.5 below)
Reactor internals	Changes in dimension due to void swelling	Plant specific	Reactor Vessel Internals (B2.1.27) Program	Consistent with GALL. GALL recommends further evaluation (see Section 3.1.2.2.6 below)
PWR core support pads, instrument tubes (bottom head penetrations), pressurizer spray heads and nozzles for the steam generator instruments and drains	Crack initiation and growth due to SCC and/or PWSCC	Plant specific	Water Chemistry (B2.1.37) and Nickel-Alloy Nozzles and Penetrations Inspection (B2.1.26) Programs	Consistent with GALL. GALL recommends further evaluation (see Section 3.1.2.2.7 below)
CASS reactor coolant system piping	Crack initiation and growth due to SCC	Plant specific	Water Chemistry (B2.1.37) and Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (B2.1.34) Programs	Consistent with GALL. GALL recommends further evaluation (see Section 3.1.2.2.7 below)
Pressurizer instrumentation penetrations and heater sheaths and sleeves made of Ni-alloys	Crack initiation and growth due to PWSCC	Inservice Inspection; Water Chemistry	None since there are no pressurizer components fabricated from Alloy 600	Consistent with GALL. GALL recommends further evaluation (see Section 3.1.2.2.7 below)
Westinghouse and B&W baffle/former bolts	Crack initiation and growth due to SCC and IASCC	Plant specific	Water Chemistry (B2.1.37); ASME Section XI, Subsections IWB, IWC, & IWD Inservice Inspection (B2.1.2); and Reactor Vessel Internals (B2.1.27) Programs	Consistent with GALL. GALL recommends further evaluation (see Section 3.1.2.2.8 below)

Component Group	**Aging Effect/Mechanism**	**AMP in GALL Report**	**AMP in LRA**	**Staff Evaluation**
Westinghouse and B&W baffle/former bolts	Loss of preload due to stress relaxation	Plant specific	ASME Section XI, Subsections IWB, IWC, & IWD Inservice Inspection (B2.1.2) and Reactor Vessel Internals (B2.1.27) Programs	Consistent with GALL. GALL recommends further evaluation (see Section 3.1.2.2.9 below)
Steam generator feedwater impingement plate and support	Loss of section thickness due to erosion	Plant specific	None, not applicable for Ginna	Consistent with GALL. GALL recommends further evaluation (see Section 3.1.2.2.10 below)
Steam generator tubes, repair sleeves, and plugs	Crack initiation and growth due to PWSCC, ODSCC, and/or IGA or loss of material due to wastage and pitting corrosion, and fretting and wear; or deformation due to corrosion at tube support plate intersections	Steam Generator Tubing Integrity; Water Chemistry	Water Chemistry (B2.1.37) and Steam Generator Integrity (B2.1.31) Programs	Consistent with GALL. GALL recommends further evaluation (see Section 3.1.2.2.11 below)
Tube support lattice bars made of carbon steel	Loss of section thickness due to FAC	Plant specific	None since component fabricated from Type 410 stainless steel	Consistent with GALL. GALL recommends further evaluation (see Section 3.1.2.2.12 below)
Carbon steel tube support plate	Ligament cracking due to corrosion	Plant specific	Water Chemistry (B2.1.37) and Steam Generator Integrity (B2.1.31) Programs	Consistent with GALL. GALL recommends further evaluation (see Section 3.1.2.2.13 below)
Steam generator feedwater inlet ring and supports	Loss of material due to flow corrosion	CE Steam Generator Feedwater Ring Inspection	Water Chemistry (B2.1.37) and Steam Generator Integrity (B2.1.31) Programs	Consistent with GALL. GALL recommends further evaluation (see Section 3.1.2.2.14 below)
Reactor vessel closure studs and stud assembly	Crack initiation and growth due to SCC and/or IGSCC	Reactor Head Closure Studs	Reactor Head Closure Studs (B2.1.25) Program	Consistent with GALL (see Section 3.1.2.1 below)
CASS pump casing and valve body	Loss of fracture toughness due to thermal aging embrittlement	Inservice Inspection	ASME Section XI, Subsections IWB, IWC, & IWD Inservice Inspection (B2.1.2) Program	Consistent with GALL (see Section 3.1.2.1 below)
CASS piping	Loss of fracture toughness due to thermal aging embrittlement	Thermal Aging Embrittlement of CASS	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (B2.1.34) Program	Consistent with GALL (see Section 3.1.2.1 below)
BWR piping and fittings; steam generator components	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (B2.1.15) Program	BWR piping—Not applicable. Steam generator components are discussed in SER Section 3.1.2.3.4

Component Group	Aging Effect/Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
RCPB valve closure bolting, manway and holding bolting, and closure bolting in high pressure and high temperature systems	Loss of material due to wear; loss of preload due to stress relaxation; crack initiation and growth due to cyclic loading and/or SCC	Bolting Integrity	Bolting Integrity (B2.1.5) and ASME Section XI, Subsections IWB, IWC, & IWD Inservice Inspection (B2.1.2) Programs	Consistent with GALL (see Section 3.1.2.1 below)
BWR feedwater and CRD return line nozzles	Crack initiation and growth due to cyclic loading	BWR Feedwater Nozzle; CRD Return Line Nozzle	Water Chemistry (B2.1.37) and Nickel-Alloy Nozzles and Penetrations Inspection (B2.1.26) Programs	BWR—Not applicable since Ginna is a PWR
Vessel shell attachment welds	Crack initiation and growth due to SCC, IGSCC	BWR Vessel ID Attachment Welds; Water Chemistry	Not applicable since Ginna is a PWR	BWR—Not applicable since Ginna is a PWR
Nozzle safe ends, recirculation pump casing, connected systems piping and fittings, body and bonnet of valves	Crack initiation and growth due to SCC, IGSCC	BWR Stress-Corrosion Cracking; Water Chemistry	Not applicable since Ginna is a PWR	BWR—Not applicable since Ginna is a PWR
Penetrations	Crack initiation and growth due to SCC, IGSCC, cyclic loading	BWR Penetrations; Water Chemistry	Not applicable since Ginna is a PWR	BWR—Not applicable since Ginna is a PWR
Core shroud and core plate, support structure, top guide, core spray lines and spargers, jet pump assemblies, control rod drive housing, nuclear instrumentation guide tubes	Crack initiation and growth due to SCC, IGSCC, IASCC	BWR Vessel Internals; Water Chemistry	Not applicable since Ginna is a PWR	BWR—Not applicable since Ginna is a PWR
Core shroud and core plate access hole cover (welded and mechanical covers)	Crack initiation and growth due to SCC, IGSCC, IASCC	ASME Section XI Inservice Inspection; Water Chemistry	Not applicable since Ginna is a PWR	BWR—Not applicable since Ginna is a PWR
Jet pump assembly castings; orificed fuel support	Loss of fracture toughness due to thermal aging and neutron embrittlement	Thermal Aging and Neutron Irradiation Embrittlement	Not applicable since Ginna is a PWR	BWR—Not applicable since Ginna is a PWR
Unclad top head and nozzles	Loss of material due to general, pitting, and crevice corrosion	Inservice Inspection; Water Chemistry	Not applicable since Ginna is a PWR	BWR—Not applicable since Ginna is a PWR
CRD nozzle	Crack initiation and growth due to PWSCC	Nickel-Alloy Nozzles and Penetrations; Water Chemistry	Water Chemistry (B2.1.37) and Nickel-Alloy Nozzles and Penetrations Inspection (B2.1.26) Programs	Consistent with GALL (see Section 3.1.2.1 below)
Reactor vessel nozzles safe ends and CRD housing; reactor coolant system components (except CASS and bolting)	Crack initiation and growth due to cyclic loading, and/or SCC and PWSCC	Inservice Inspection; Water Chemistry	Water Chemistry (B2.1.37) and ASME Section XI, Subsections IWB, IWC, & IWD Inservice Inspection (B2.1.2) Programs	Consistent with GALL (see Section 3.1.2.1 below)

Component Group	Aging Effect/Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Reactor vessel internals CASS components	Loss of fracture toughness due to thermal aging, neutron irradiation embrittlement, and void swelling	Thermal Aging and Neutron Irradiation Embrittlement	None since no reactor vessel internals components made of CASS that serve a license renewal function have been identified	None since no reactor vessel internals components made of CASS that serve a license renewal function have been identified
External surfaces of carbon steel components in reactor coolant system pressure boundary	Loss of material due to boric acid corrosion	Boric Acid Corrosion	Boric Acid Corrosion (B2.1.6) Program	Consistent with GALL (see Section 3.1.2.1 below)
Once through steam generator secondary manways and handholds (CS)	Loss of material due to erosion	Inservice Inspection	None since Ginna does not have a once through steam generator	Consistent with GALL (see Section 3.1.2.1 below)
Reactor internals, reactor vessel closure studs, and core support pads	Loss of material due to wear	Inservice Inspection	ASME Section XI, Subsections IWB, IWC, & IWD Inservice Inspection (B2.1.2) Program	Consistent with GALL (see Section 3.1.2.1 below)
Pressurizer integral support	Crack initiation and growth due to cyclic loading	Inservice Inspection	ASME Section XI, Subsections IWB, IWC, & IWD Inservice Inspection (B2.1.2) Program	Consistent with GALL (see Section 3.1.2.1 below)
Upper and lower internal assembly (Westinghouse)	Loss of preload due to stress relaxation	Inservice Inspection; Loose Part and/or Neutron Noise Monitoring	ASME Section XI, Subsections IWB, IWC, & IWD Inservice Inspection (B2.1.2) Program	Not consistent with GALL—no loose parts and no neutron noise monitoring (see SER Section 3.1.2.4.3.2).
Reactor vessel internals in fuel zone region (except Westinghouse and B&W baffle bolts)	Loss of fracture toughness due to neutron irradiation embrittlement and void swelling	PWR Vessel Internals; Water Chemistry	Reactor Vessel Internals (B2.1.27) Program	Consistent with GALL (see Section 3.1.2.1 below)
Steam generator upper and lower heads; tubesheets; primary nozzles and safe ends	Crack initiation and growth due to SCC, PWSCC, IASCC	Inservice Inspection; Water Chemistry	Water Chemistry (B2.1.37) and ASME Section XI, Subsections IWB, IWC, & IWD Inservice Inspection (B2.1.2) Programs	Consistent with GALL (see Section 3.1.2.1 below)
Vessel internals (except Westinghouse and B&W baffle former bolts)	Crack initiation and growth due to SCC and IASCC	PWR Vessel Internals; Water Chemistry	Water Chemistry (B2.1.37) and ASME Section XI, Subsections IWB, IWC, & IWD Inservice Inspection (B2.1.2) Programs	Consistent with GALL (see Section 3.1.2.1 below)
Reactor internals (B&W screws and bolts)	Loss of preload due to stress relaxation	Inservice inspection; Loose Part Monitoring	Not applicable since Ginna is not a B&W designed plant	Consistent with GALL (see Section 3.1.2.1 below)
Reactor vessel closure studs and stud assembly	Loss of material due to wear	Reactor Head Closure Studs	Reactor Head Closure Studs (B2.1.25) Program	Consistent with GALL (see Section 3.1.2.1 below)

Component Group	Aging Effect/Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Reactor internals (Westinghouse upper and lower internal assemblies; CE bolts and tie rods)	Loss of preload due to stress relaxation	Inservice Inspection; Loose Part Monitoring	ASME Section XI, Subsections IWB, IWC, & IWD Inservice Inspection (B2.1.2) Program	Not consistent with GALL—No loose parts and no neutron noise monitoring (see SER Section 3.1.2.4.3.2).

The staff's review of the reactor systems group for the Ginna LRA is contained within four sections of this SER. Section 3.1.2.1 is the staff review of components in the reactor systems that the applicant indicates are consistent with the GALL Report and do not require further evaluation. Section 3.1.2.2 is the staff review of components in the reactor systems that the applicant indicates are consistent with GALL and for which GALL recommends further evaluation. Section 3.1.2.3 is the staff evaluation of AMPs that are specific to the reactor systems. Section 3.1.2.4 contains an evaluation of the adequacy of aging management for components in each system in the reactor systems group and includes an evaluation of components in the reactor systems that the applicant indicates are not in GALL. Section 3.1.2.4 is divided into six subsections—reactor coolant (Class 1), reactor vessel, reactor vessel internals, pressurizer, steam generators, and reactor coolant (Non-Class 1).

3.1.2.1 Aging Management Evaluations in the GALL Report That Are Relied on for License Renewal, Which Do Not Require Further Evaluation

For component groups evaluated in the GALL Report for which the applicant has claimed consistency with GALL, and for which GALL does not recommend further evaluation, the staff sampled components to determine whether the plant-specific components contained in these GALL component groups were bounded by the GALL evaluation. The staff also sampled component groups to determine whether the applicant had properly identified those component groups in GALL that were not applicable to its plant. The staff identified several areas where additional information or clarification was needed. The staff's evaluation of the applicant's responses to those RAIs is included in Section 3.1.2.4 of this SER. On the basis of its review, the staff has verified the applicant's claim of consistency with the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 50.21(a)(3).

3.1.2.1.1 Cracking of CRD Housings

Programs identified in the GALL Report are generic programs. When components experience unusual aging effects, the programs identified in GALL may not be applicable. Control rod drive (CRD) housings (LRA Table 3.2-1, Item 23) are identified as being susceptible to SCC and PWSCC with aging management provided by the Water Chemistry Program (B2.1.37) and the Reactor Vessel Head Penetration Program (B2.1.26). Cracking has been reported on CRD housings at Fort Calhoun (letter dated January 25, 2002, from Omaha Public Power District (OPPD)) and Palisades (Nuclear Management Company letters to NRC dated August 20, 2001, and March 14, 2002). To determine whether the proposed AMPs are adequate for the Ginna CRD housings, the staff requested that (a) the applicant compare the design and materials used in the Ginna CRD housings to those in the Palisades and Fort Calhoun housings, and (b) the applicant provide the inspection history for the Ginna CRD housings.

In response to RAI 3.1.2-1, in a letter dated May 13, 2003, the applicant indicated that the materials of construction and design of the CRD housings at Fort Calhoun and Palisades, which are both Combustion Engineering design plants, are different from those at Ginna, which is a Westinghouse design plant. The CRD housings at Fort Calhoun and Palisades are flanged and bolted. The upper housing assembly is fabricated from Type 347 stainless steel. The cracking observed at Fort Calhoun occurred at the upper housing assembly pipe-to-eccentric reducer weld. The through-wall crack was axially oriented and located in the weld. No such configuration or materials exist in the Ginna CRD housings.

The upper CRD housings on the Ginna reactor vessel are joined to the CRD nozzle adapters by a threaded connection which is the pressure boundary. The adapter and housing are both Type 304 stainless steel. The Type 304 adapter is welded to the Alloy 600 CRD nozzle by a full penetration single V-groove butt weld using Alloy 82/182 weld metal. These welds have been periodically examined on the peripheral CRD rows by both dye-penetrant and ultrasonic testing. No evidence of leakage from these welds has ever been observed. The upper CRD housing contains no pressure-boundary welds, and therefore the combination of materials and design which resulted in the cracking observed at Fort Calhoun and Palisades does not exist at Ginna. Since the CRD upper housings at Ginna do not contain welds and the cracking at Fort Calhoun was observed in the welds in the CRD upper housing, the Ginna CRD upper housings will not be susceptible to the type of cracking observed in the Fort Calhoun CRD upper housings and the proposed AMPs need not be modified.

3.1.2.2 Aging Management Evaluations in the GALL Report That Are Relied on for License Renewal, for Which GALL Recommends Further Evaluation

For component groups evaluated in the GALL Report for which the applicant has claimed consistency with GALL, and for which GALL recommends further evaluation, the staff reviewed the applicant's evaluation to determine whether it adequately addressed the issues for which GALL recommended further evaluation. In addition, the staff sampled components in these groups to determine whether the plant-specific components contained in these GALL component groups were bounded by the GALL evaluation.

The GALL Report indicates that further evaluation should be performed for the aging effects discussed in the following subsections.

3.1.2.2.1 Cumulative Fatigue Damage

Fatigue is a time-limited aging analysis (TLAA) as defined in 10 CFR 54.3. The TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The staff's evaluation of this TLAA is documented in Section 4.3 of this SER, following the guidance in Section 4.3 of the SRP-LR.

3.1.2.2.2 Loss of Material Due to Pitting and Crevice Corrosion

Loss of material due to pitting and crevice corrosion could occur in the pressurized-water reactor (PWR) steam generator shell assembly. The existing program relies on control of chemistry to mitigate corrosion and ISI to detect loss of material. The extent and schedule of the existing steam generator inspections are designed to ensure that flaws cannot attain a depth sufficient to threaten the integrity of the welds. However, according to NRC Information Notice (IN) 90-04, “Cracking of the Upper Shell-to-Transition Cone Girth Welds in Steam Generators,” January 26, 1990, if general corrosion pitting of the shell exists, the program may not be sufficient to detect pitting and corrosion. The GALL Report recommends augmented inspection to manage this aging effect. The staff review verifies that the applicant has proposed a program that will manage loss of material due to pitting and crevice corrosion by providing enhanced inspection and supplemental methods to detect loss of material and ensure that the component intended functions will be maintained during the period of extended operation.

The applicant proposed the Water Chemistry (B2.1.37), ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection (B2.1.2), and Steam Generator Integrity (B2.1.31) Programs to manage loss of material due to pitting and crevice corrosion in steam generator shell assembly. The Water Chemistry Program is reviewed in SER Section 3.0.3.1. The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program is reviewed in SER Section 3.0.3.2. The Steam Generator Integrity Program is reviewed in SER Section 3.1.2.3.5.

On the basis of its review, the staff finds that the applicant has adequately evaluated the AMR results involving management of loss of material due to pitting and crevice corrosion for components in the reactor system, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with the GALL Report, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.3 Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement

Certain aspects of neutron irradiation embrittlement are TLAAs as defined in 10 CFR 54.3. The TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The staff’s evaluation of this TLAA can be found in Section 4.2 of this SER, following the guidance in Section 4.2 of the SRP-LR.

Loss of fracture toughness due to neutron irradiation embrittlement could occur in the reactor vessel. A Reactor Vessel Materials Surveillance Program monitors neutron irradiation embrittlement of the reactor vessel. Reactor vessel surveillance programs are plant specific, depending on matters such as the composition of limiting materials, availability of surveillance capsules, and projected fluence levels. In accordance with Appendix H to 10 CFR Part 50, an applicant is required to submit its proposed withdrawal schedule for approval prior to implementation. Thus, further staff evaluation is required for license renewal. The GALL Report recommends further evaluation of the Reactor Vessel Materials Surveillance Program for the period of extended operation. The staff verifies that the applicant has proposed an adequate Reactor Vessel Materials Surveillance Program for the period of extended operation.

The limiting beltline material in the Ginna reactor vessel is the intermediate-to-lower shell beltline circumferential weld. The Ginna Reactor Vessel Surveillance Program, in conjunction with the TLAA, effectively manages loss of fracture toughness in the beltline materials. The Reactor Vessel Surveillance Program provides adequate material property and neutron dosimetry data to predict fracture toughness in beltline materials at the end of the period of extended operation. In addition, equivalent margins analyses have been performed in accordance with 10 CFR 50, Appendix G methods. These fracture mechanics analyses (see TLAAs, SER Section 4.2) provide assurance that beltline material toughness values in the Ginna reactor vessel will remain at acceptable levels through the period of extended operation. The Reactor Vessel Surveillance Program is reviewed in SER Section 3.1.2.3.4.

Loss of fracture toughness due to neutron irradiation embrittlement and void swelling could occur in Westinghouse and Babcock and Wilcox (B&W) baffle/former bolts. The staff reviews the applicant's proposed program on a case-by-case basis to ensure that an adequate program will be in place for management of these aging effects. A combination of the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program and the Reactor Vessel Internals Program will be used to manage loss of fracture toughness due to neutron irradiation embrittlement and void swelling in baffle/former bolts. Ginna will continue to participate in Westinghouse Owners Group (WOG) activities and monitor industry initiatives for the purpose of evaluating the significance of void swelling on selected PWR reactor vessel internals components. As new information and technology become available, the plant-specific Reactor Vessel Internals Program will be modified to incorporate enhanced surveillance techniques.

On the basis of its review, the staff finds that the applicant appropriately evaluated AMR results involving management of loss of fracture toughness due to neutron irradiation embrittlement for components in the reactor system, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with the GALL Report, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.4 Crack Initiation and Growth Due to Thermal and Mechanical Loading or Stress-Corrosion Cracking

Crack initiation and growth due to thermal and mechanical loading or SCC (including intergranular stress-corrosion cracking (IGSCC)) could occur in small-bore reactor coolant systems and connected system piping less than NPS 4 inches. The existing program relies on ASME Section XI ISI and on control of water chemistry to mitigate SCC. The GALL Report recommends that a plant-specific destructive examination or an NDE that permits inspection of the inside surfaces of the piping be conducted to ensure that cracking has not occurred and the component intended function will be maintained during the extended period. The AMPs should be augmented by verifying that service-induced weld cracking is not occurring in the small-bore piping less than NPS 4 inches, including pipe, fittings, and branch connections. A one-time inspection of a sample of locations is an acceptable method to ensure that the aging effect is not occurring and that the component's intended function will be maintained during the period of extended operation. GALL Chapter XI.M32, "One-Time Inspection," contains an acceptable verification method.

The GALL Report recommends that the inspection include a representative sample of the system population, and, where practical and prudent, focus on the bounding or lead components most susceptible to aging due to time in service, severity of operating conditions, and lowest design margin. For small-bore piping, actual inspection locations should be based on physical accessibility, exposure levels, NDE techniques, and locations identified in IN 97-46, "Unisolable Crack in High-Pressure Injection Piping." Combinations of NDE, including visual, ultrasonic, and surface techniques, are performed by qualified personnel following procedures consistent with the ASME Code and 10 CFR 50 Appendix B. For small-bore piping less than NPS 4 inches, including pipe, fittings, and branch connections, a plant-specific destructive examination or NDE that permits inspection of the inside surfaces of the piping should be conducted to ensure that cracking has not occurred. Followup of unacceptable inspection findings should include expansion of the inspection sample size and locations. The inspection and test techniques prescribed by the program should verify any aging effects because these techniques, used by qualified personnel, have been proven effective and consistent with staff expectations. The staff's review confirms that the program includes measures to verify that unacceptable degradation is not occurring, thereby validating the effectiveness of existing programs, or confirming that there is no need to manage aging-related degradation for the period of extended operation. If an applicant proposes a one-time inspection of select components and susceptible locations to ensure that corrosion is not occurring, the reviewer verifies that the proposed inspection will be performed using techniques similar to ASME code and ASTM standards, including visual, ultrasonic, and surface techniques, to ensure that the component's intended function will be maintained during the period of extended operation.

Aging management of service-induced cracking will be accomplished by a combination of the Water Chemistry Control Program and the One-Time Inspection Program (described in Appendix B to the LRA). A sample of small-bore piping welds will be inspected using appropriate volumetric examination techniques near, but prior to, the end of the current license period. This sample will be selected to include various piping sizes, configurations, and flow conditions. If a flaw is detected in the sample, the successive examinations described in ASME Code, Section XI, IWB-2420 and additional examinations as described in IWB-2430 would apply as appropriate.

Based on operating experiences of small-bore piping in the RCS, the staff is concerned that small-bore piping in the RCS could be susceptible to SCC and thermal fatigue resulting from turbulent penetration and thermal stratification.

In response to RAI 3.2.1-1, in a letter dated May 13, 2003, the applicant indicated that the sample population of small-bore (less than 4 inches NPS) Class 1 RCS and connected systems piping welds will be derived using ASME Section XI Code, 1995 Edition with 1996 Addenda, Category B–J. All locations are considered susceptible to cracking due to SCC. An assessment of small-bore piping for susceptibility to thermal fatigue has also been performed.

This assessment included Class 1 piping systems that are connected to the reactor coolant pressure boundary and are normally stagnant and not isolable from the reactor coolant pressure boundary, including safety injection, residual heat removal, drain, alternate charging, and auxiliary spray lines. The assessment addressed the potential for leakage, stratification, and turbulence penetration using interim thermal fatigue management guidelines developed by EPRI/Materials Reliability Program (MRP). Locations judged to be potentially susceptible to thermal fatigue will be included in the sample population of small-bore piping to be examined by an appropriate volumetric technique.

The GALL Report recommends that a plant-specific AMP be evaluated for the management of crack initiation and growth due to thermal and mechanical loading or SCC (including IGSCC) in boiling-water reactor (BWR) vessel flange leak detection line and BWR jet pump sensing line. Since reactor vessel flange leak detection lines are also utilized in PWRs, this issue is applicable to PWRs. The staff reviews the applicant’s proposed program on a case-by-case basis to ensure that an adequate program will be in place for the management of these aging effects.

The reactor vessel leak detection line is fabricated from stainless steel. The portion of the line that is in the scope of license renewal is included in the small-bore piping category. Aging management of service-induced cracking will be accomplished by a combination of the Water Chemistry Control Program and the One-Time Inspection Program (described in Appendix B to the LRA).

The GALL Report’s AMP XI.M32 indicates the one-time inspection is to be utilized when an aging effect is not expected to occur, but there is insufficient data to completely rule it out or an aging effect is expected to progress very slowly. The one-time inspection provides additional assurance that either aging is not occurring or the evidence of aging is so insignificant that an AMP is not warranted. In order to determine whether crack initiation and growth for the reactor vessel flange leak detection line are not expected to occur, the applicant must review its inspection records to determine whether this aging effect has previously occurred at Ginna. If it has not occurred, the proposed program is acceptable. If a component has experienced this aging effect in the past, the applicant should identify when it occurred, the corrective action, and the reason for not expecting it to occur in the future. If this aging effect is expected to occur in the future, periodic examination is necessary.

In response to RAI 3.1.2-2, in a letter dated May 13, 2003, the applicant indicated that a review of plant-specific operating experience revealed that there had been no age-related degradation of the reactor vessel flange leak detection line. Since there has been no age-related degradation of the reactor vessel flange leak detection line, the staff believes that cracking of this line is not likely, and therefore, the One-Time Inspection Program is appropriate for managing the aging effect of crack initiation and growth.

On the basis of its review, the staff finds that the applicant appropriately evaluated AMR results involving management of crack initiation and growth due to thermal and mechanical loading or SCC for components in the reactor system, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with the GALL Report, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.5 Crack Growth Due to Cyclic Loading

The GALL Report recommends further evaluation of programs to manage crack growth due to cyclic loading in the reactor vessel shell. Crack growth due to cyclic loading in reactor vessel shells is evaluated as a TLAA. Growth of intergranular separations (underclad cracks) in low-alloy or carbon steel heat-affected zones under austenitic stainless steel cladding is a TLAA to be evaluated for the period of extended operation for all the SA 508-Cl 2 forgings where the cladding was deposited with a high-heat input welding process. The methodology for evaluating the underclad flaw should be consistent with the current well-established flaw evaluation procedure and criterion in the ASME Section XI Code. Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses," of the SRP-LR provides generic guidance for meeting the requirements of 10 CFR 54.21(c). The staff's evaluation of this TLAA can be found in Section 4.3.2.3 of this SER, following the guidance in Section 4.7 of the SRP-LR.

3.1.2.2.6 Changes in Dimension Due to Void Swelling (Pressurized-Water Reactor)

Changes in dimension due to void swelling could occur in reactor vessel internal components. The GALL Report recommends further evaluation to ensure that this aging effect is adequately managed. The reactor vessel internals receive a visual inspection (VT-3) according to Category B-N-3 of Subsection IXB of ASME Section XI. However, this inspection is not sufficient to detect the effects of changes in dimension due to void swelling. Therefore, the GALL Report recommends that a plant-specific AMP should be evaluated. The applicant provided a plant-specific AMP or participates in industry programs to investigate aging effects and determine an appropriate AMP. Otherwise, the applicant provided the basis for concluding that void swelling is not an issue for the component. The applicant should either provide the basis for concluding that void swelling is not an issue for the component or provide a program to manage the effects of changes in dimension due to void swelling and the loss of ductility associated with swelling. The staff verifies that the applicant has either proposed a program to manage changes in dimension due to void swelling in the pressure vessel internal components or provided the basis for concluding that void swelling is not an issue.

The Reactor Vessel Internals Program manages changes in dimension due to void swelling. In addition to ISIs performed according to the requirements of ASME Section XI, Subsection IWB, the Reactor Vessel Internals Program provides for augmented visual (VT-1) inspections for certain susceptible (or limiting) components using high-resolution techniques yet to be developed. Ginna will continue to participate in industry investigations of aging effects applicable to reactor vessel internals, as well as initiatives to develop advanced inspection techniques which will permit resolution and measurement of very small features of interest. Ginna will incorporate applicable results of industry initiatives related to void swelling in the Reactor Vessel Internals Program.

On the basis of its review, the staff finds that the applicant appropriately evaluated AMR results involving management of changes in dimension due to void swelling for components in the reactor system, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with the GALL Report, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.7 Crack Initiation and Growth Due to Stress-Corrosion Cracking or Primary Water Stress-Corrosion Cracking

Crack initiation and growth due to SCC and PWSCC could occur in PWR core support pads (or core guide lugs), instrument tubes (bottom head penetrations), pressurizer spray heads, and nozzles for the steam generator instruments and drains. The GALL Report recommends further evaluation to ensure that these aging effects are adequately managed. The GALL Report recommends that a plant-specific AMP be evaluated because existing programs may not be capable of mitigating or detecting crack initiation and growth due to SCC. Acceptance criteria are described in Branch Technical Position RLSB-1 (Appendix A.1 to the SRP-LR). The staff reviews the applicant's proposed program to ensure that an adequate program will be in place for the management of these aging effects.

Crack initiation and growth due to SCC could occur in PWR cast austenitic stainless steel (CASS) RCS piping and fittings and the pressurizer surge line nozzle. For PWRs, the GALL Report recommends further evaluation of piping that does not meet the reactor water chemistry guidelines of TR-105714, "PWR Primary Water Chemistry Guidelines, Revision 3," November 1995. Acceptance criteria are described in Branch Technical Position RLSB-1 (Appendix A.1 to the SRP-LR). The staff reviews the applicant's proposed program to ensure that an adequate program will be in place for the management of these aging effects.

Crack initiation and growth due to PWSCC could occur in PWR pressurizer instrumentation penetrations and heater sheaths and sleeves made of nickel-based alloys. The existing program relies on ASME Section XI ISI and on control of water chemistry to mitigate PWSCC. However, the existing program should be augmented to manage the effects of SCC on the intended function of components fabricated from nickel-based alloys. The GALL Report recommends that the applicant provide a plant-specific AMP or participate in industry programs to determine an appropriate AMP for PWSCC of the Inconel 182 weld. Acceptance criteria are described in Branch Technical Position RLSB-1 (Appendix A.1 to the SRP-LR). The staff reviews the applicant's proposed program to ensure that an adequate program will be in place for the management of these aging effects.

The pressurizer spray head performs no license renewal intended functions as defined in 10 CFR 54.4 at Ginna. Therefore, AMR review is not required for the pressurizer spray head. In response to RAI 3.2.2-2, in a letter dated May 13, 2003, the applicant indicated that there are no locations in the RCS piping at Ginna which contain Alloy 82/182 welds or weld buttering. The only Alloy 600 and Alloy 82/182 materials in the RCS at Ginna are located in the reactor vessel and the replacement steam generators. The CRDM nozzles in the reactor vessel closure head and the BMI penetrations in the bottom head are Alloy 600 and are welded to the heads with partial penetration J-groove Alloy 82/182 welds. The radial core support pads in the reactor vessel are Alloy 600 and are welded to the lower shell with Alloy 82/182 weld metal. The tubesheets in the replacement steam generators are overlaid with Alloy 82 weld metal (nonpressure boundary). The reactor vessel closure head is scheduled to be replaced at Ginna in the fall of 2003. The replacement head will have Alloy 690 penetrations welded to the head with partial penetration J-groove Alloy 52 welds. In response to RAI 3.2.1-2, in a letter dated May 13, 2003, the applicant indicates that the core support pads and bottom head instrumentation penetrations are included in the scope of the Nickel-Alloy Nozzles and Penetrations Inspection Program and will be evaluated as part of any industry initiatives related to management of cracking in Alloy 600 penetrations. The Nickel-Alloy Nozzles and Penetrations Inspection Program is a plant-specific program which includes participation in industry initiatives related to management of Alloy 600 penetration cracking issues. The Reactor Vessel Head Penetration Program is discussed in SER Section 3.1.2.3.2.

The steam generator instrument nozzles are low-alloy steel, not Alloy 600, and therefore are not included in this component group. Since the steam generator instrument nozzles are fabricated from low-alloy steel, they are not susceptible to crack initiation and growth due to SCC or PWSCC.

The RCS piping is forged Type 316 stainless steel and the fittings (elbows) and RCP casings are CASS (Type CF8M). Crack initiation and growth due to SCC was identified as an aging effect requiring management for RCS CASS components. The Ginna Water Chemistry Control Program monitors and controls primary water chemistry in accordance with the guidelines of EPRI TR-105714 (Revision 5). Since the Water Chemistry Control Program is in accordance with the guidelines of EPRI TR-105714, the Type 316 stainless steel and CASS (Type CF8M) components will not be susceptible to crack initiation and growth due to SCC or PWSCC.

Instrument penetrations, heater well tubes, and adapters are wrought Type 316 stainless steel. Since instrumentation, heater well tubes, and adapters are not fabricated from nickel based alloys, they are not susceptible to crack initiation and growth due to SCC or PWSCC in PWR reactor coolant.

On the basis of its review, the staff finds that the applicant appropriately evaluated AMR results involving management of crack initiation and growth due to SCC or PWSCC for components in the reactor system, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with the GALL Report, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.8 Crack Initiation and Growth Due to Stress-Corrosion Cracking or Irradiation-Assisted Stress-Corrosion Cracking

Crack initiation and growth due to SCC or irradiation-assisted stress-corrosion cracking (IASCC) could occur in baffle/former bolts in Westinghouse and Babcock & Wilcox (B&W) reactors.

A combination of the Water Chemistry Control Program, ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, and the Reactor Vessel Internals Program will be used to manage this aging effect. Ginna will continue to participate in WOG activities and monitor industry initiatives for the purpose of evaluating the significance of cracking due to IASCC on selected PWR reactor vessel internals components. As new information and technology become available, the plant-specific Reactor Vessel Internals Program will be modified to incorporate enhanced surveillance techniques.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of crack initiation and growth due to SCC or IASCC for components in the reactor system, as recommended in the GALL Report. On the basis of this finding, and the finding that the remainder of the applicant’s program is consistent with GALL, the staff concludes that there is reasonable assurance that this aging effect will be adequately managed during the period of extended operation.

3.1.2.2.9 Loss of Preload Due to Stress Relaxation

Loss of preload due to stress relaxation could occur in baffle/former bolts in Westinghouse and B&W reactors.

Loss of preload due to stress relaxation will be managed jointly by the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program and the Reactor Vessel Internals Program. Ginna will continue to participate in industry investigations of aging effects applicable to reactor vessel internals as well as initiatives to develop advanced inspection techniques which will permit resolution and measurement of very small features of interest. Aging management activities or surveillance techniques resulting from these initiatives will be incorporated, as required, as enhancements to the Reactor Vessel Internals Program.

On the basis of its review, the staff finds that the applicant appropriately evaluated AMR results involving management of loss of preload due to stress relaxation for components in the reactor system, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with the GALL Report, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.10 Loss of Section Thickness Due to Erosion

Loss of section thickness due to erosion could occur in steam generator feedwater impingement plates and supports. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that this aging effect is adequately managed. Acceptance criteria are described in Branch Technical Position RLSB-1 (Appendix A.1 to the SRP-LR). The staff reviews the applicant's proposed program to ensure that an adequate program will be in place for the management of these aging effects. This component group is not applicable to Ginna because the feedwater delivery system to the steam generators is through feed rings to Alloy 690 J-tubes.

3.1.2.2.11 Crack Initiation and Growth Due to PWSCC, ODSCC, or Intergranular Attack, or Loss of Material Due to Wastage and Pitting Corrosion, or Loss of Section Thickness Due to Fretting and Wear, or Denting Due to Corrosion of Carbon Steel Tube Support Plate

Crack initiation and growth due to PWSCC, ODSCC, or IGA, or loss of material due to wastage and pitting corrosion, or deformation due to corrosion, could occur in Alloy 600 components of the steam generator tubes, repair sleeves, and plugs. All PWR licensees have committed voluntarily to a steam generator degradation management program described in NEI 97-06, "Steam Generator Program Guidelines." The GALL Report recommends that an AMP based on the recommendations of staff-approved NEI 97-06 guidelines, or other alternate regulatory basis for steam generator degradation management, should be developed to ensure that this aging effect is adequately managed. At present, the staff does not plan to endorse NEI 97-06 or detailed industry guidelines referenced therein. The staff is working with the industry to revise plant technical specifications to incorporate the essential elements of the industry's NEI 97-06 initiative, as necessary, to ensure tube integrity is maintained. This would require implementation of programs to ensure that performance criteria for tube structural and leakage integrity are maintained, consistent with the plant design and licensing basis. The NEI 97-06 document provides guidance on programmatic details for accomplishing this objective. These guidelines apply to all degradation or damage mechanisms. However, these programmatic details would be outside the scope of the technical specifications. As part of the NRC Reactor Oversight Program, the NRC would monitor the effectiveness of these programs in terms of whether the goals of these programs are being met; namely, that the tube structural and leakage integrity performance criteria are in fact being maintained. The staff reviews the applicant's proposed program to ensure that an adequate program will be in place for the management of these aging effects for the period of extended operation.

The applicant has proposed to manage (1) crack initiation and growth due to PWSCC, ODSCC, or IGA, or (2) loss of material due to wastage and pitting corrosion, or (3) loss of section thickness due to fretting and wear, or (4) denting due to corrosion of carbon steel tube support plate, in the steam generator tubes, repair sleeves, and plugs by the Steam Generator Integrity Program and Water Chemistry Control Program. The staff's review of the Steam Generator Integrity Program is discussed in SER Section 3.1.2.3.5. The staff's review of the Water Chemistry Control Program is discussed in SER Section 3.0.3.1.

On the basis of its review, the staff finds that the applicant appropriately evaluated AMR results involving management of crack initiation and growth due to PWSCC, ODSCC, or IGA or loss of material due to wastage and pitting corrosion, or loss of section thickness due to fretting and wear, or denting due to corrosion of carbon steel tube support plate for components in the reactor system, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with the GALL Report, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.12 Loss of Section Thickness Due to Flow-Accelerated Corrosion

Loss of section thickness due to FAC could occur in steam generator tube support lattice bars made of carbon steel. The GALL Report recommends further evaluation of loss of section thickness due to FAC of the tube support lattice bars made of carbon steel. The GALL Report recommends a plant-specific AMP be evaluated and, on the basis of the guidelines of NRC GL 97-06, an inspection program for steam generator internals should be developed to ensure that this aging effect is adequately managed. The staff reviews the applicant’s proposed program to ensure that an adequate program will be in place for the management of these aging effects. Acceptance criteria are described in Branch Technical Position RLSB-1 (Appendix A.1 to the SRP-LR).

Tube support lattice bars are fabricated from Type 410 stainless steel in Ginna replacement steam generators. Type 410 stainless steel is not susceptible to FAC. Therefore, this component group is not applicable to Ginna. A discussion of steam generator components susceptible to FAC is given in Item 21 in Table 3.2-1 of the application.

On the basis of its review, the staff finds that the applicant appropriately evaluated AMR results involving management of loss of section thickness due to flow-accelerated corrosion for components in the reactor system, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with the GALL Report, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.13 Ligament Cracking Due to Corrosion

Section IV.D1.2-k of the GALL Report states that ligament cracking due to corrosion could occur in carbon steel tube support plates in the steam generators and recommends further evaluation. In Item 17 in LRA Table 3.2-1, the applicant indicates that there are no carbon steel tube support plates in Ginna steam generators. In Item 16 in LRA Table 3.2-1, the applicant stated that the tube support lattice bars in the Ginna steam generators are fabricated from Type 410 stainless steel. The staff finds that ligament cracking due to corrosion is not applicable to the stainless steel tube support lattice bars in the Ginna steam generators because this aging effect applies most often to carbon steel tube support plates with a drilled hole configuration.

Although ligament cracking due to corrosion is not applicable to the lattice grid support bars, the applicant identified cracking due to SCC and loss of material due to pitting and crevice corrosion as the aging effects requiring management for the lattice grid support bars in the Ginna steam generators as discussed in Item 17 in Table 3.2-1. The applicant also identified the Water Chemistry Control Program and the Steam Generator Integrity Program as managing these aging effects.

The staff finds these two AMPs are acceptable to manage the associated aging effects because the periodic inspections specified in the Steam Generator Integrity Program will detect potential degradation in the lattice grid support bars. The Water Chemistry Control Program will mitigate the potential for corrosion of the lattice grid support bars. The staff evaluated the Water Chemistry Control Program and the Steam Generator Integrity Programs in Sections 3.0.3.1 and 3.1.2.3.5 of this SER, respectively.

In addition, all PWR licensees, including the applicant, have committed voluntarily to a steam generator degradation management program described in NEI 97-06; these guidelines are currently under NRC staff review. The GALL Report recommends that an AMP based on the recommendations of NEI 97-06 guidelines, or other alternate regulatory basis for steam generator degradation management, be developed to ensure that the aging effects associated with steam generators are adequately managed. The staff reviews the applicants' proposed program on a case-by-case basis to ensure that an adequate program will be in place for the management of these aging effects. The inspection of the tube lattice support bars is a part of the steam generator degradation management program specified in NEI 97-06.

The staff finds that although ligament cracking due to corrosion is not applicable to the stainless steel lattice grid support bars in the Ginna steam generators, the applicant appropriately evaluated AMR results involving management of cracking due to SCC and loss of material due to pitting and crevice corrosion for the lattice grid support bars. Since the applicant's AMR results are otherwise consistent with the GALL Report, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.14 Loss of Material Due to Flow-Accelerated Corrosion

As specified in GALL Section IV.D1.3-a, loss of material due to FAC could occur in the feedwater inlet ring and supports. Section IV.D1.3-a of the GALL Report recommends that a plant-specific AMP be evaluated to manage loss of material due to flow-accelerated corrosion in the feedwater inlet ring and supports. As noted in IN 90-04, "Cracking of the Upper Shell-to-Transition Cone Girth Welds in Steam Generators," IN 91-19, "Steam Generator Feedwater Distribution Piping Damage," and licensee event report (LER) 50-362/90-05-01, this form of degradation has been detected only in certain Combustion Engineering (CE) System 80 steam generators. The GALL Report recommends that a plant-specific AMP be evaluated because existing programs may not be capable of mitigating or detecting loss of material due to FAC. Acceptance criteria are described in Branch Technical Position RLSB-1 (Appendix A.1 to the

SRP-LR). The staff reviews the applicant's proposed program to ensure that an adequate program will be in place for the management of these aging effects.

In C-RAI B2.1.31-1, the staff requested the applicant to clarify the components that are considered in the scope of the steam generator internals. By letter dated July 11, 2003, the applicant stated that the steam generator internals include among other components, feedring and feedring gooseneck and J-tubes. By letter dated December 19, 2003, the applicant added to LRA Tables 3.2-2 Items 35 and 36 to include the feedwater inlet ring components and supports as steam generator components that needed to be considered for aging management. Item 35 includes steam generator feedring and feedring gooseneck and supports. Item 36 includes J-tubes which are attached to the feedwater inlet ring. For Items 35 and 36, the applicant identified loss of material due to FAC as the aging effect. The applicant also identified the Water Chemistry Control Program and Steam Generator Integrity Program as managing the aging effects. The applicant stated further that the Steam Generator Integrity Program provides for periodic visual inspection of the feedring and feedring gooseneck, J-tubes, and associated supports.

In its response to C-RAI B2.1.31-1, by letter dated July 11, 2003, the applicant stated that secondary-side inspections of the Ginna steam generators are presently performed whenever primary-side inspections are performed (i.e., every other refueling outage or every 3 years). This schedule is based on the latest revision of the EPRI PWR Steam Generator Examination Guidelines, Revision 6, effective in fall 2003, along with NRC Regulatory Guide 1.83, Revision 1, July 1975. The applicant stated further that the secondary-side inspections of the steam generators are consistent with the guidelines of NEI 97-06. The inspections cover many secondary-side components including accessible feedwater inlet J-tubes. Any condition observed by the inspection which does not meet the acceptance criteria in the NDE procedures or any condition judged by the examiner to require further investigation is documented and evaluated in accordance with the Ginna Station Corrective Action Program.

The staff finds that the Water Chemistry Control Program and Steam Generator Integrity Program are acceptable to manage the associated aging effects of the steam generator feedring components and supports because the periodic inspections specified in the Steam Generator Integrity Program will detect potential degradation in the feedring components from loss of material due to FAC. The Water Chemistry Control Program will mitigate the potential for corrosion of the feedring components.

In addition, the staff finds that the above inspection schedule and procedure are acceptable for the feedring components and associated supports because the applicant follows the industry guidelines.

3.1.2.2.15 Conclusions

The staff has reviewed the applicant's evaluation of the issues for which GALL recommends further evaluation for components in the reactor systems. On the basis of its review, the staff finds that the applicant has adequately evaluated the management of the issues for which the GALL Report recommends further evaluation for components in the reactor system. On the basis of this finding, and the finding that the remainder of the applicant's program is consistent with GALL, the staff concludes that there is reasonable assurance that these aging effects will be adequately managed during the period of extended operation.

3.1.2.3 Aging Management Programs for Reactor Coolant System Components

In SER Sections 3.1.2.1 and 3.1.2.2, the staff determined that the applicant's AMRs and associated AMPs will adequately manage component aging in the reactor systems. The staff then reviewed specific components in the reactor systems to ensure that they were properly evaluated in the applicant's AMR.

To perform its evaluation, the staff reviewed the components listed in LRA Tables 2.3.1-1 through 2.3.1-6 to determine whether the applicant had properly identified the applicable AMRs and AMPs needed to adequately manage the aging effects for the components. This portion of the staff review involved identification of the aging effects for each component, ensuring that each aging effect was evaluated using the appropriate AMR in Section 3, and that management of the aging effect was captured in the appropriate AMP. The results of the staff's review are provided below.

The staff also reviewed the UFSAR Supplements for the AMPs credited with managing aging in reactor system components to determine whether the program description is adequate.

The applicant credits 15 AMPs with managing the aging effects associated with components in the RCS. Seven of the AMPs are credited with managing aging of components in other system groups (common AMPs), while eight AMPs are credited with managing aging only for RCS components. The staff's evaluation of the common AMPs that are credited with managing aging in RCS components is provided in Section 3.0.3 of this SER. The following is a list of common AMPs, along with their section numbers:

- Water Chemistry Program (3.0.3.1)
- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program (3.0.3.2)
- Bolting Integrity Program (3.0.3.3)
- Boric Acid Corrosion Prevention Program (3.0.3.4)
- One-Time Inspection Program (3.0.3.7)
- Periodic Surveillance and Preventive Maintenance Program (3.0.3.8)
- System Monitoring Program (3.0.3.11)

The staff's evaluation of the seven RCS AMPs is provided below.

3.1.2.3.1 Reactor Head Closure Studs Program

3.1.2.3.1.1 <u>Summary of Technical Information in the Application</u>. The applicant's Reactor Head Closure Studs Program is discussed in LRA Section B2.1.25, "Reactor Head Closure Studs." Component Item 18 in Table 3.2-1 indicates that this program is consistent with GALL except that SCC has not been identified as an applicable aging effect. The Reactor Head Closure Stud Program includes (a) ISI in accordance with the requirements of the ASME Code, Section XI, Subsection IWB, 1995 Edition with 1996 Addenda, Table IWB 2500-1, and (b) preventive measures to mitigate cracking. The ISI portion of the program is described in its entirety in the program description for “ASME Section XI, Subsections IWB, IWC, and IWD, Inservice Inspection.” The reactor head closure studs are fabricated from ASME SA-320 Grade L43 (American Iron and Steel Institute (AISI) 4340) low-alloy steel and according to the applicant are not susceptible to SCC (specified minimum yield strength of 105 ksi). A comprehensive discussion of this subject is provided in the program description for “Bolting Integrity,” (SER Section 3.0.3.3).

3.1.2.3.1.2 Staff Evaluation. The GALL Report indicates that reactor head closure studs are susceptible to loss of material due to wear and to crack initiation and growth due to SCC. The GALL Report recommends the Chapter XI.M3, “Reactor Head Closure Studs,” program as acceptable for mitigating and monitoring these aging effects. This program relies on ASME Code Section XI, Subsection IWB to monitor and detect this aging effect. Preventive measures identified in the GALL program include avoiding the use of metal-plated stud bolting to prevent degradation due to corrosion or hydrogen embrittlement and using manganese phosphate or other acceptable surface treatments and stable lubricants (RG 1.65). In response to C-RAI 4.2.2-1, in a letter dated July 30, 2003, the applicant stated that the reactor vessel closure studs are not plated with a metal coating. The studs were “Parkerized,” which is a process for producing a manganese phosphate surface coating on steels. The lubricant used on the studs is N-7000, which is a stable, high-purity, metal-free, anti-seize lubricant suitable for use up to 2400 °F. The coating process and lubricants used for the closure head studs will prevent degradation due to corrosion or hydrogen embrittlement.

Section B2.1.25 of the LRA indicates that the reactor head closure studs are fabricated from ASME SA-320 Grade L43 (AISI 4340) low-alloy steel and are not susceptible to SCC. The studs are fabricated with a specified minimum yield strength of 105 ksi. In response to RAI B2.1.25-1, in a letter dated May 13, 2003, the applicant provided its plant-specific inspection experience and described mitigation measures initiated at Ginna to prevent SCC. The reactor head closure studs have been periodically inspected under the ASME Section XI Inservice Inspection Program. All 48 studs have been inspected during each 10-year ISI interval. Both surface (magnetic particle) and volumetric (ultrasonic) inspections were performed on each stud. No evidence of degradation has ever been reported on any of the studs.

"Degradation and Failure of Bolting in Nuclear Power Plants” (EPRI NP-5769) indicates that for bolting materials with yield strength less than 150 ksi, susceptibility to SCC should not be considered a problem provided lubricants containing molybdenum disulfide are not used. Use of such lubricants is specifically prohibited under the Ginna Quality Assurance Program. Since the studs are fabricated with a specified minimum yield strength of 105 ksi, it is possible that they could be heat treated to a yield stress of 150 ksi and could be susceptible to SCC. However, since the Reactor Head Closure Studs Program relies on ASME Code Section XI, Subsection IWB to monitor for SCC, this aging effect will be managed by this program.

3.1.2.3.1.3 Conclusions. On the basis of its review and audit of the applicant’s program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with GALL. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.1.2.3.2 Reactor Vessel Head Penetration Inspection

3.1.2.3.2.1 Summary of Technical Information in the Application. The applicant describes the AMP for reactor vessel head penetration inspection in Section B2.1.26 of the LRA.
The applicant stated that this program includes (1) a PWSCC susceptibility assessment to identify susceptible components, (2) monitoring and control of reactor coolant water chemistry to mitigate PWSCC, and (3) ASME Code ISI of reactor vessel head penetrations and bottom-mounted instrument tube penetrations. The 10 program elements were briefly described.

Significant operating experience regarding the PWSCC of Alloy 600 vessel head penetrations has been documented in GL 97-01 and NRC Bulletins 2001-01 and 2002-01. In response to GL 97-01, comprehensive eddy current examinations of the reactor pressure vessel (RPV) head penetrations were performed at Ginna in 1999. No significant degradation was found. However, the applicant has plans to proactively replace the reactor vessel head and CRDM penetrations with penetrations using Alloy 690TT material. This replacement is scheduled for fall of 2003. The bottom-mounted instrument penetrations were routinely examined in accordance with ASME Section XI, Subsection IWB-2500-1. The applicant stated that the type and extent of inspections for the new reactor vessel head will be determined as Ginna continues to follow industry events and developments.

3.1.2.3.2.2 Staff Evaluation. In its response to the staff's RAI (RAI B2.1.26-1), the applicant stated that the Nickel-Alloy Nozzles and Penetrations Inspection Program is consistent with the guidelines provided in AMP XI.M11, "Nickel-Alloy Nozzles and Penetrations," of NUREG-1801 (GALL Report) and complies with NRC Order EA-03-009, "Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors," issued on February 11, 2003. No exception to the GALL Program XI.M11 was identified. The staff confirmed the applicant's claim of consistency during the AMP audit.

In response to GL 97-01, the applicant used a probabilistic model developed by Westinghouse for WOG plants to assess the susceptibility to PWSCC of reactor vessel head penetrations. Based on this model, the RPV head penetrations at Ginna fell into the less than 15 effective full-power year (EFPY) category, representing moderate susceptibility.

Based on the guidelines provided in the NRC order of February 11, 2003, the susceptibility ranking in terms of effective degradation years (EDY) can be calculated based on head temperature at 100 percent power and the operating time at each specific head temperature. The calculated EDY for the RPV head at Ginna is 16.182, which is in category "high."

The applicant indicated that susceptibility models for other Alloy 600 and 82/182 pressure boundary components have not yet been developed. The applicant will perform a susceptibility assessment when the models become available.

The applicant has scheduled replacement of the reactor vessel head during the fall 2003 refueling outage. The new head will have enhancements in materials and design. The CRDM penetrations will be fabricated with Alloy 690TT (UNSN06690 thermally treated) with Alloy 52 (UNS 06052) for weld buttering and J-groove welds. Both thermal-treated Alloy 690 and Alloy 52 will provide enhanced resistance to PWSCC. The replacement head will also be insulated with mirror insulation, allowing full access to the exterior surface and the interface of each penetration with head for bare metal visual inspections.

The applicant stated that the RPV bottom head penetrations at Ginna are expected to be much less susceptible to PWSCC than the CRDM penetrations at the top head for the following reasons:

- much lower operating temperature
- lower residual stresses resulting from welding due to much smaller size in bottom head penetrations
- lower residual stresses resulting from straightening process due to less stringent requirements in verticality
- stress relieved with reactor vessel bottom head after completion of installation of bottom head penetrations

The applicant also stated that Ginna is committed to participate in industry initiatives and closely follow relevant industry operating experience related to bottom head penetration degradation and that appropriate susceptibility assessments will be made as new models become available.

In a response to the staff's RAI (RAI 3.2.2-2) regarding the V.C. Summer event where a through-wall crack developed in a primary loop hot-leg reactor vessel nozzle to pipe weld made of Alloy 182/82 materials, the applicant stated that there are no locations in the RCS piping at Ginna which contain Alloy 82-182 welds or weld buttering. The applicant identified the following locations in the reactor vessel and the replacement steam generators as containing Alloy 600 and Alloy 82/182 materials:

- The CRDM nozzle in the reactor vessel closure head and the BMI penetrations in the bottom head are Alloy 600 and are welded to the heads with partial penetration J-groove Alloy 82/182 welds.

- The radial core support lugs in the reactor vessel are Alloy 600 and are welded to the lower shell with Alloy 82/182 weld metal.

- The tubesheets in the replacement steam generators are overlaid with Alloy 82 weld metal (nonpressure boundary).

The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program. The staff finds the subject supplement acceptable.

3.1.2.3.2.3 Conclusions. On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with GALL. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.1.2.3.3 Reactor Vessel Internals Program

3.1.2.3.3.1 Summary of Technical Information in the Application. The applicant's Reactor Vessel Internals Program is discussed in LRA Section B2.1.27, "Reactor Vessel Internals." The applicant stated that this program is consistent with NUREG-1801 relative to monitoring and control of reactor coolant water chemistry in accordance with the EPRI Guidelines in TR-105714. Rochester Gas & Electric Corporation is also committed to ASME Section XI, Subsection IWB, 1995 Edition with 1996 Addenda. The current ASME Section XI Inservice Inspection Program is considered to provide reasonable assurance that aging effects will be managed such that the intended functions of reactor vessel internal (RVI) components will be maintained during the license renewal period. That notwithstanding, RG&E will participate in industry activities concerning the development of augmented inspection techniques in order to visually inspect for fine cracks (0.0005 inch) and other changes in dimension in nonbolted components.

3.1.2.3.3.2 Staff Evaluation. The applicant must identify whether all 10 elements of the program are in accordance with GALL Program XI.M16 and whether the applicant's program contains any exceptions or enhancements to the 10 elements in GALL Program XI.M16.

In response to RAI B2.1.27-2, in a letter dated May 13, 2003, the applicant indicated that the Reactor Vessel Internals Program is consistent with, but includes one exception to, GALL

Section XI.M16, “PWR Vessel Internals.” The only exception is that NUREG-1801, Section XI.M16, specifies examination schedules in accordance with IWB-2400, which requires core support structures to be inspected once during each 10-year interval. While this is correctly applied to the VT-3 examinations, some augmented examinations as specified by the industry recommended program may be performed only once, unless degradation is detected.

The applicant will participate in industry activities concerning the development of augmented inspection techniques for inspection of core support structures. The required inspections and frequency of inspection will depend upon the results of the industry program on RVI. Therefore, the exception may not be relevant and will be further evaluated by the staff when the results of the industry program are known. In a letter dated September 16, 2003, the applicant indicated that the Reactor Vessel Internals Program will be submitted for staff review and approval prior to Ginna entering the period of extended operation. Since the applicant will be submitting the program for staff review and approval (reference item 31 in Appendix A to this SER) prior to entering the period of extended operation, the staff will be able to review the program to ensure all issues have been addressed. This completes the staff review of the Reactor Vessel Internals Program at this time and resolves RAI B2.1.27-2.

Section B2.1.27 of the LRA identifies the following RVI components as most susceptible to crack initiation and growth due to IASCC and loss of fracture toughness due to neutron irradiation embrittlement and/or void swelling:

- lower core plate and fuel alignment pins
- lower support columns
- core barrel and core barrel flange in active core region
- thermal shield and neutron panels
- bolting–lower support column, baffle–former, and barrel–former

The staff requested that the applicant explain why these components were selected as the RVI components most susceptible to crack initiation and growth due to IASCC and loss of fracture toughness due to neutron irradiation embrittlement and/or void swelling. In response to RAI B2.1.27, in a letter dated May 13, 2003, the applicant indicated that these components were identified as most susceptible to IASCC, neutron embrittlement, and void swelling because they are being exposed to the highest in-core neutron radiation fields. Since these components are exposed to the highest in-core neutron radiation field, the staff agrees that these components will be most susceptible to crack initiation and growth due to IASCC and loss of fracture toughness due to neutron irradiation embrittlement and void swelling.

3.1.2.3.3.3 Conclusions. On the basis of its review and audit of the applicant’s program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with GALL. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.1.2.3.4 Reactor Vessel Surveillance Program

3.1.2.3.4.1 Summary of Technical Information in the Application. The applicant's Reactor Vessel Surveillance Program is discussed in LRA Section B2.1.28, "Reactor Vessel Surveillance." The applicant stated that the program is consistent with NUREG-1801, GALL Report, Section XI.M31, "Reactor Vessel Surveillance."

3.1.2.3.4.2 Staff Evaluation. In LRA Section B2.1.28, "Reactor Vessel Surveillance," the applicant described its AMP to manage aging in reactor vessel beltline materials. The LRA stated that this AMP is consistent with GALL AMP XI.M31, "Reactor Vessel Surveillance," with no deviations. For this AMP, GALL recommends further evaluation. The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program. Furthermore, the staff reviewed the applicant's evaluation to determine whether it addressed the additional issues recommended in the GALL Report and confirmed that the AMP would adequately address these issues. Finally, the staff determined whether the applicant properly applied the GALL program to its facility.

Section B2.1.28 indicates that an additional capsule will be withdrawn at a neutron fluence equivalent to approximately 52 EFPYs of exposure. Items 5 through 7 in GALL XI.M31 provide recommendations for withdrawal of capsules during the period of license renewal. The staff requested that the applicant identify how the Ginna capsule withdrawal schedule for the period of license renewal complies with Items 5 through 7 in GALL XI.M31. In response to RAI B2.1.28-1, the applicant indicated that Ginna has two surveillance capsules left in the core. The current schedule is to withdraw one of the capsules during the 2003 refueling outage. At that time, the capsule will have received a fast neutron fluence of 5.25×10^{19}, more than the projected dose at 60 years of 4.85×10^{19}. Since Ginna has performed, and submitted to the NRC, a reactor vessel equivalent margins analysis, RG&E indicated that it does not plan on testing that capsule. In addition, the current plan is to leave one capsule in the reactor vessel until about 2009, at which point it will have received a fast neutron fluence equivalent to 80 years of operation. Since Item 6 in GALL XI.M31 indicates the applicant is to withdraw one capsule at an outage in which the capsule receives a neutron fluence equivalent to the 60-year fluence to test the capsule in accordance with the requirements of ASTM E-185, the staff believes the capsule withdrawn during the 2003 refueling outage should be tested. Testing of this capsule is important because the reference temperature for pressurized thermal shock (RT_{PTS}) value in the pressurized thermal shock evaluation was determined using Ginna surveillance data. The highest capsule neutron fluence is 3.746×10^{19} n/cm^2, which is below the neutron fluence projected for the reactor vessel at the end of the period of extended operation. Testing this capsule, which has a projected neutron fluence of 5.25×10^{19} n/cm^2, will ensure that the reactor vessel will remain below the pressurized thermal shock screening criteria at the end of the period of extended operation. Item 7 in GALL XI.M31 indicates applicants without in-vessel capsules during the period of extended operation should use alternative dosimetry to monitor neutron fluence during the period of extended operation. Since the last capsule is to be removed in 2009, and capsules will not be available to determine the neutron fluence during the period of extended operation, alternative dosimetry should be utilized during the period of extended operation to monitor neutron fluence.

In response to C-RAI 4.2-1, in a letter dated July 30, 2003, the applicant indicated that the capsule withdrawn in 2003 will not be tested in accordance with Table 10, Footnote E, in ASTM E-185. This footnote indicates this capsule may be held without testing following withdrawal. The requirements in ASTM E-185 provide guidance for withdrawal and testing for 40 years of operation. Also in this clarification response, the applicant indicated that Item 7 in GALL XI.M31 is not applicable to Ginna because the applicant will be using the guidance in Item 6. Items 6 and 7 are separate guidance, and they should not be substituted for each other. Based on the above discussion, the staff believes this capsule should be tested. This was Open Item B2.1.28-1.

In a letter dated December 9, 2003, the applicant indicated that the next surveillance capsule should be withdrawn in the spring 2005 refueling outage, at which time it will have accumulated fluence slightly greater than that anticipated for 60 years of operation. The applicant indicates that testing of the capsule will be performed prior to the time that the fluence of the latest capsule, Capsule S, is exceeded (approximately 2012). This is not acceptable because paragraph IV.A in Appendix H to 10 CFR Part 50 requires that the reporting of capsule test results must be submitted to the NRC within 1 year of the date of capsule withdrawal unless an extension is granted by the Director, Office of Nuclear Reactor Regulation. In a letter dated December 19, 2003, the applicant committed (reference item 38 in Appendix A to this SER) to submit the data and analysis from the capsule withdrawn in the spring of 2005 within 1 year of the date of the capsule withdrawal, in accordance with paragraph IV.A in Appendix H to 10 CFR Part 50.

The last Ginna surveillance capsule is to be removed shortly after it accumulates a fluence equivalent to 80 years of operation. The capsule specimens are to be held without testing following withdrawal. This is acceptable at this time since the license is being extended only to 60 years of operation. However, it is planned that the applicant would reinsert the dosimetry monitors, such that neutron flux could continue to be monitored during the period of extended operation. Since the applicant will have data for 60 years of operation and will be able to monitor neutron flux throughout the period of extended operation, the Reactor Vessel Surveillance Program is acceptable. This resolves Open Item B2.1.28-1.

3.1.2.3.4.3 Conclusions. On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with GALL. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.1.2.3.5 Steam Generator Integrity Program

3.1.2.3.5.1 Summary of Technical Information in the Application. The applicant's Steam Generator Integrity Program is discussed in LRA Section B2.1.31, "Steam Generator Integrity Program." The applicant stated that the program is consistent with GALL Program XI.M19, "Steam Generator Integrity." In its response to RAI B2.1.31-1, the applicant added enhanced aging management activities to address plant-specific AMP requirements identified in Table 3.2-1 of the LRA, and plant-specific components, beyond those discussed in GALL and identified in Table 3.2-2 of the LRA, for which the Steam Generator Integrity Program is identified as an AMP.

This AMP is credited with managing aging in the steam generator shell assembly; steam generator tubes, repair sleeves, and plugs; and other secondary-side components.

The applicant stated that the Steam Generator Integrity Program manages aging effects such as cracking due to PWSCC, ODSCC, IGA, pitting, wastage, wear fouling due to corrosion product buildup, mechanical degradation due to denting and impingement damage, and fatigue. The applicant further stated that the Steam Generator Integrity Program manages these aging effects/mechanisms through a balance of prevention, inspection, examination, assessment, evaluation, repair, and leakage monitoring measures. The program is administered through a series of plant directives and interface procedures, as well as the plant technical specifications. Key program attributes include NDE, sludge lancing, primary and secondary water chemistry control, and primary-to-secondary leakage trending and monitoring. Lastly, in June 1996, the steam generators at Ginna were replaced with steam generators with a new design which incorporate design and manufacturing improvements to reduce and/or prevent many of the problems that the industry experienced with the original design.

3.1.2.3.5.2 Staff Evaluation. In LRA Section B2.1.31, "Steam Generator Integrity Program," the applicant described its AMP to manage aging in steam generator components. The LRA stated that this AMP is consistent with GALL AMP XI.M19, "Steam Generator Tube Integrity," with the exception that the applicant included aging management activities to address plant-specific AMP requirements identified in Table 3.2-1 of the LRA, and the applicant added plant-specific components, beyond those discussed in GALL and identified in Tables 3.2-1 and 3.2-2 of the LRA, for which the Steam Generator Integrity Program is identified as an AMP. For this AMP, GALL recommends further evaluation. The staff reviewed the applicant's evaluation to determine whether it addressed the issues recommended for further evaluation in the GALL Report and to confirm whether the AMP would adequately address these issues. In addition, the staff reviewed the clarifications and related justifications to determine whether the AMP remains adequate to manage the aging effects for which it is credited. Furthermore, the staff reviewed the UFSAR Supplement to determine whether it provides an adequate description of the revised program. Finally, for Ginna, the staff determined whether the applicant properly applied the GALL program to its facility.

3.1.2.3.5.2.1 Crack Initiation and Growth Due to PWSCC, ODSCC, or Intergranular Attack, or Loss of Material Due to Wastage and Pitting Corrosion, or Loss of Section Thickness Due to Fretting and Wear, or Denting Due to Corrosion of Carbon Steel Tube Support Plate.
This program manages tube degradation related to corrosion phenomena, such as PWSCC, ODSCC, IGA, pitting, and wastage, along with other mechanically induced phenomena, such as denting, wear, impingement damage, and fatigue. Nondestructive examination techniques are used to identify tubes that are defective and need to be removed from service or repaired in accordance with the guidelines of the plant technical specifications. In addition, operational leakage limits are included to ensure that, should substantial tube leakage develop, prompt action is taken to shut down the plant and limit the frequency of steam generator tube ruptures. In addition, this program manages degradation of steam generator repair sleeves and plugs.

The program incorporates provisions of NEI 97-06, “Steam Generator Program Guidelines,” which includes an assessment of degradation mechanisms that considers operating experience from similar steam generators to identify degradation mechanisms and, for each mechanism, defines the inspection techniques, measurement uncertainty, and sampling strategy.
The industry guidelines provide criteria for the qualification of personnel, specific techniques, and the associated acquisition and analysis of data, including procedures, probe selection, analysis protocols, and reporting criteria. The performance criteria pertain to structural integrity, accident-induced leakage, and operational leakage. The Steam Generator Monitoring Program includes guidance on assessment of degradation mechanisms, inspection, tube integrity assessment, maintenance, plugging, repair, and leakage monitoring, as well as procedures for monitoring and controlling secondary-side and primary-side water chemistry. The Water Chemistry Program for PWRs relies on monitoring and control of reactor (primary) water chemistry and secondary water chemistry. Generic revisions to the standard technical specifications based on the provisions of NEI 97-06 are currently being reviewed by the NRC staff. Since this review is ongoing, the applicant's program was reviewed on a plant-specific basis. The NRC regulations including the plant technical specifications provide an adequate regulatory basis for managing the effects of aging on the steam generator tubes.

The applicant has proposed to use the Steam Generator Integrity Program and Water Chemistry Control Program to manage (1) crack initiation and growth due to PWSCC, ODSCC, or IGA, or (2) loss of material due to wastage and pitting corrosion, or (3) loss of section thickness due to fretting and wear, or (4) denting due to corrosion of carbon steel tube support plate, in the steam generator tubes, repair sleeves, and plugs. The staff’s review of the Steam Generator Integrity Program is discussed here. The staff’s review of the Water Chemistry Control Program is discussed in Section 3.0.3.1 of this SER. The applicant stated that the Steam Generator Integrity Program is consistent with GALL Report Section XI.M19, “Steam Generator Tube Integrity Program,” and incorporates guidance contained in NEI 97-06.

On the basis of its review and audit of the applicant’s program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with GALL. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.1.2.3.5.2.2 Plant-Specific Components from Tables 3.2-1 and 3.2-2 of the LRA.
The applicant identified a number of plant-specific components which referenced the Steam Generator Integrity Program as the program which manages aging of those components. Since the AMP in the GALL Report is related only to steam generator tubes, the staff reviewed the aging management activities related to the additional components against the 10 program elements using the Branch Technical Position RLSB-1 in Appendix A of the SRP-LR. The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program.

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 the requirements of Appendix B to 10 CFR Part 50, and covers all structures and components subject to AMR. The staff evaluation of the applicant's Quality Assurance Program is provided separately in Section 3.0.4 of this SER. This program satisfies the elements of corrective actions, confirmation process, and administrative controls.
The remaining seven elements are discussed below.

Program Scope. The applicant described the inspection program related to the steam generator shell assembly, repair sleeves and plugs, and lattice grid tube supports and U-bend fan bar restraints. The staff finds it is reasonable to include these components in the Steam Generator Integrity Program, because the applicant adequately addressed the remaining nine AMP program elements.

Preventive Actions. In response to RAI B2.1.31-1, the applicant described the control of primary and secondary water chemistry, as described in the Water Chemistry Control Program, as measures in place to mitigate the degradation related to corrosion of primary- and secondary-side steam generator components. In addition, the applicant indicated that the NEI 97-06 guidelines include foreign material exclusion requirements. The staff finds this acceptable because these actions will assist in managing the degradation of the affected components.

Parameters Monitored/Inspected. In response to RAI B2.1.31-1, the applicant identified the steam generator tube volumetric inspection technique (i.e., eddy current testing) as the primary means of monitoring for degradation of steam generator tubes. In addition, the applicant indicated that secondary-side visual inspections and foreign object surveys and retrieval (FOSAR) inspections are the primary means of monitoring the secondary-side steam generator components to provide reasonable assurance of the detection of degradation which could lead to loss of intended functions. The staff finds this acceptable because these types of inspections will provide meaningful information regarding aging of the secondary-side steam generator components.

Detection of Aging Effects. In response to RAI B2.1.31-1, the applicant stated that the primary method for detection of tube aging effects is by eddy current testing in accordance with Revision 5 of the EPRI Steam Generator Examination Guidelines. The extent and schedule of the inspections prescribed by the program are designed to ensure that flaws do not exceed established performance criteria. The extent and schedule of the inspections prescribed by the program are designed to ensure timely detection and replacement of leaking repair plugs and sleeves. In addition, periodic visual inspections of the secondary side, including mid- and upper bundle, tube support structure (such as lattice grid tube supports and U-bend fan bar restraints), accessible areas of the shell, and upper internals, provide assurance of early detection of age-related degradation of secondary-side structural components.

In response to an NRC request for clarification of RAI B2.1.31-1, the applicant stated that secondary-side inspections of the steam generators are presently performed whenever primary-side inspections are performed (i.e., every other refueling outage). The applicant also provided additional details on the scope of the secondary-side inspections, which are stated to be consistent with the guidelines of NEI 97-06.

The staff finds that the methods, scope, and extent of inspections are acceptable because they provide a valid method for detection of the aging effects in the steam generator secondary-side components.

Monitoring and Trending. In response to RAI B2.1.31-1, the applicant indicated that condition monitoring assessments are performed after each inspection to determine whether steam generator tube structural and accident leakage criteria were satisfied. In addition, operational assessments are performed to verify that structural and accident leakage criteria are maintained during the operating interval until the next required inspection. Comparison of the results of the condition monitoring assessment with the predictions of the previous operational assessment provides feedback for evaluation of the adequacy of the operational assessment and additional insights that can be incorporated into the next operational assessment. The staff finds this acceptable because this process will allow the applicant to adequately monitor and trend the aging effects in the steam generator.

Acceptance Criteria. In response to RAI B2.1.31-1, the applicant stated that the acceptance criteria for the steam generator tubes, plugs, and sleeves are in accordance with plant technical specifications and NEI 97-06, which include ensuring that the tube integrity performance criteria are not exceeded. In response to a request for clarification of RAI B2.1.31-1, the applicant stated that visual examinations of the secondary-side steam generator components are performed by personnel qualified in accordance with the approved Ginna NDE procedures. The qualification is based on the requirements of Recommended Practice American Society for

Nondestructive Testing (ASNT) SNT-TC-1A, American Welding Society (AWS) QC1 "Qualification Standard for Visual Personnel," ANSI/ASNT CP-189 "Standard for Qualification and Certification of Nondestructive Testing Personnel," and AWS D1.1 "Structural Welding Code." Acceptance criteria for visual examinations are explicitly detailed in approved Ginna NDE procedures. Any condition observed by the visual examiner which does not meet the acceptance criteria in the NDE procedures or any condition judged by the examiner to require further investigation is documented and evaluated in accordance with the Ginna Corrective Action Program. The staff finds this acceptable because this procedure will allow the applicant to determine if the intended functions of the added components will be affected by any aging identified.

Operating Experience. The applicant indicated that in June 1996, the Ginna steam generators were replaced with a new design. The replacement steam generators incorporate design and manufacturing improvements to reduce and/or prevent many of the problems that the industry has experienced. To date, the applicant has completed steam generator tube examinations, sludge lancing, and secondary-side foreign material/loose parts inspections in accordance with the Steam Generator Integrity Program requirements during three refueling outages. No degradation has been observed. The staff concluded that this operating experience supports the applicant's conclusion that the Steam Generator Integrity Program provides reasonable assurance that aging effects will be managed such that the intended function of the components will be maintained during the license renewal period.

On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with GALL. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.1.2.3.5.3 Conclusions. On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with GALL. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.1.2.3.6 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel

3.1.2.3.6.1 Summary of Technical Information in the Application. The applicant describes the AMP for thermal aging embrittlement of CASS in Section B2.1.34 of the LRA. The applicant stated that an evaluation of the susceptibility of CASS components at Ginna was made, based on the casting method, molybdenum content, and percent of ferrite. Based on this evaluation, it was determined that the CASS RCS elbows were susceptible to loss of fracture toughness due to thermal aging.

The applicant also stated that a plant-specific flaw tolerance evaluation was conducted in Westinghouse Commercial Atomic Power (WCAP)-15837, “Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the R. E. Ginna Nuclear Power Plant for the License Renewal Program,” April 2002. The results of this evaluation showed that adequate fracture toughness exists for the RCS loop components, including the cast elbows, for the period of extended operation (60 years).

The applicant also stated that another evaluation was made for the RCP casings in WCAP-15873, “A Demonstration of the Applicability of ASME Code Case N-481 to the Primary Loop Pump Casings of R.E. Ginna Nuclear Power Plant for the License Renewal Program,” May 2002. This evaluation supported the application of Code Case N-481 to the inspection of primary loop pump casings for the period of extended operation (60 years).

3.1.2.3.6.2 Staff Evaluation. In its response to RAI B2.1.34-1, the applicant stated that the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program implemented at Ginna is consistent with the guidelines provided in AMP XI.M12, “Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS).” No exception to GALL Program XI.M12 was identified. The staff audited the subject program during the AMP audit and confirmed that the subject program is consistent with GALL AMP XI.M12.

In AMP XI.M12, it is stated that the existing ASME Section XI requirements, including the alternative requirements of ASME Code Case N-481 for pump casings, are adequate for all pump casings and valve bodies. It is also stated in the program element for detection of aging effects that, for pump casings and valve bodies and “not susceptible” piping, no additional inspection or evaluations are required to demonstrate that the material has adequate fracture toughness. “Potentially susceptible” piping can either be examined using methods that meet the criteria of the ASME Section XI, Appendix VIII, or a plant- or component-specific flaw tolerance evaluation can be performed to demonstrate that the thermally embrittled material has adequate toughness.

The applicant stated that this program covers CASS components including (1) valve bodies for valves equal or larger than 4 inches NPS, (2) RCP casings and flanges, and (3) RCS elbows.

The applicant stated that the CASS elbow to pipe welds in the RCS have been examined by UT and radiography in accordance with the ASME, Section XI, Inservice Inspection Program. No recordable indications were ever reported. The applicant reviewed the plant-specific operating experience and did not find any service-related degradation or leakage from CASS components at Ginna.

The staff finds that the CASS valve bodies are inspected by radiography at Ginna. The staff finds that radiography testing (RT) is a code acceptable inspection method for volumetric examination; therefore, based on GALL guidelines, no additional examinations or evaluations to demonstrate adequate fracture toughness are required.

The staff finds that the applicant did not provide the UFSAR Supplement for this program in its initial LRA submittal and requested the applicant to submit the UFSAR Supplement. In its response to the staff's RAI (C-RAI B2.1.34), the applicant provided the UFSAR Supplement for this program. The staff reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program. The staff finds that the subject supplement is acceptable with the exception that discussions in the supplement pertaining to the RCP casings should be deleted, since no additional examination or evaluation is required for RCP casings.

3.1.2.3.6.3 <u>Conclusions</u>. On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with GALL. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.1.2.3.7 Thimble Tube Inspection Program

3.1.2.3.7.1 <u>Summary of Technical Information in the Application</u>. The applicant's Thimble Tube Inspection Program is discussed in LRA Section B2.1.36, "Thimble Tubes Inspection." The GALL Report does not have a program that corresponds to the applicant's Thimble Tube Inspection Program. Details of this program are described in the staff's technical evaluation section of this program, which follows.

3.1.2.3.7.2 Staff Evaluation. In LRA Section B2.1.36, "Thimble Tubes Inspection," the applicant described its AMP to manage the integrity of the in-core neutron monitoring thimble tubes, which serve as a portion of the reactor coolant pressure boundary. As discussed in NRC Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors," July 26, 1988, thimble tube wall-thinning can occur as a result of flow-induced vibration. This wear damage is detected at locations associated with geometric discontinuities or area changes along the reactor coolant flow path, such as areas near the lower core plate, the core support forging, the lower tie plate, and the vessel penetrations.

The Thimble Tubes Inspection Program was initially designed to inspect for wear damage. However, the program was expanded to include inspection of the thimble and guide tubes for SCC. Section 3 of Table 3.2-2 of the application for renewed operating license, Component 1, Bottom Mounted Instrument (BMI) Guide Tubes and Seal Table Fittings, identifies these components as being susceptible to cracking from SCC. The AMP for the BMI guide tubes includes the Water Chemistry Program and ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. The AMP for the seal table fittings is the Water Chemistry Program.

In response to RAI 3.2.2-1, in a letter dated May 13, 2003, the applicant indicated that SCC is an aging effect requiring management for the BMI guide tubes because over some length, they are exposed to primary water at temperatures above 140 °F. For the seal table fittings, SCC was incorrectly identified as an aging effect requiring management because the temperature at the seal table is ambient containment temperature (i.e., less than 140 °F). In addition, the annular space between the thimble tubes and guide tubes is periodically flushed and water samples are analyzed for chloride, fluoride, and sulfate ion. Generic Letter 88-01 indicates that at temperatures below 200 °F, stainless steel components are not susceptible to SCC. Since the seal table fittings are below 200 °F and are stainless steel, the staff agrees that this component is not susceptible to SCC and aging management for SCC is not necessary.

In addition, in this response, the applicant indicates that credit is taken for the thimble tube inspections performed under the Thimble Tube Inspection Program as managing cracking due to SCC of the guide tubes. Details of these inspections, including scope, examination method, acceptance criteria, and examination frequencies, are included in the Thimble Tube Inspection Program description in Section B2.1.36 of the LRA. All thimble tube inspections are performed by personnel qualified in accordance with the requirements of ASME Section XI, Article IWA-2300, SNT-TC-1A, and ANSI/ASNT CP-189. Since the outside diameter surface of the thimble tubes is exposed to the same environment as the inner diameter surface of the guide tube, and both components are fabricated from stainless steel, they would both be susceptible to SCC. The Thimble Tube Inspection Program, as described in Section B2.1.36 of the LRA, was for detection of wear, not SCC. In order for the thimble tube inspection to be utilized for detection of SCC in the guide tube, the Thimble Tube Inspection Program must be modified to include inspection for SCC. The staff requested that the applicant revise the Thimble Tube Inspection Program and the associated Ginna inspection procedures to perform inspections for SCC.

In response to C-RAI 3.2.2-1 in a letter dated July 30, 2003, the applicant revised Section A2.1.25 to indicate that the Thimble Tube Inspection Program is credited for managing cracking due to SCC of the thimble and guide tubes and revised Section B2.1.36 to indicate that the aging effects which are detected by eddy current testing of the thimble tube are loss of material due to fretting wear and cracking due to SCC.

This AMP is not evaluated in GALL. Therefore, the staff reviewed this AMP against the 10 program elements using the guidance in Branch Technical Position RLSB-1 in Appendix A of the SRP-LR. Three of the 10 attributes are associated with the quality assurance activities of corrective action, confirmation processes, and administrative controls and are discussed in Section 3.0.4 of this SER. The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program.

<u>Program Scope</u>. The applicant's program inspects locations in the thimble tube associated with geometric discontinuities or area changes along the reactor coolant flow path, such as areas near the lower core plate, the core support forging, the lower tie plate, and the vessel penetrations because these are locations that are susceptible to wear resulting from flow-induced vibration. The applicant stated that all 36 thimble tubes are within the scope of this inspection program. The staff found the scope of the program to be adequate because all 36 thimble tubes are within scope and the inspection is performed at the locations most susceptible to wear resulting from flow-induced vibration. The applicant had not identified the locations on the thimble tubes and guide tubes to be inspected for SCC. This was Open Item B2.1.36-1(a).

In a letter dated December 9, 2003, the applicant indicated that the entire length of each thimble tube is to be inspected for SCC by eddy current examination. Since the applicant will inspect the entire length of each thimble tube, the scope of the program is acceptable. This resolves Open Item B2.1.36-1(a).

<u>Preventive Actions</u>. As noted in Operating Experience below, the replacement of tube G-6 with chrome plating at the wear area constitutes a preventive action. In addition, flushing of the tubes during refueling outages is also considered mitigative in nature. Eddy current examinations are performed on a periodicity consistent with the severity of wear damage for each thimble tube. When wall loss in a tube exceeds 55 percent, but is less than 65 percent, the tube is repositioned such that wear is redistributed, or other corrective action is taken. Table 3.2-2 indicates that the Water Chemistry Control Program is the activity for managing cracking due to SCC. The Water Chemistry Program is an acceptable preventive action because it will reduce the impurities in the reactor coolant that cause SCC.

<u>Parameters Monitored/Inspected</u>. The eddy current examinations determine the wall thickness of the thimble tubes, allowing an assessment of the wear, and wear rate, of each tube in each location. Eddy current examination will also be utilized to detect SCC. This is acceptable because eddy current examination has been successfully utilized to determine wall thickness and wear rate. The applicant had not identified whether the eddy current examination had been qualified to detect and size SCC. This was Open Item B2.1.36-1(b). The applicant, in a letter dated December 9, 2003, indicated the following:

> Eddy current examination will be performed using eddy current probes that are capable of detecting axially and circumferentially-oriented flaws. The eddy current examination technique has been qualified for detection of SCC, in that Ginna operating experience indicates that OD-initiated SCC indications 20% through-wall and greater are consistently detectable. Since sizing of SCC indications from eddy current data is somewhat unreliable, remediation criteria are based on detection. Any thimble tube containing an SCC indication detected by eddy current examination is removed from service (isolated) and/or replaced. The guide tube in which the "cracked" thimble tube resides would then be considered potentially cracked, and the guide tube would be inspected using an appropriate volumetric technique, such as eddy current testing (ECT) or ultrasonic testing (UT).

Based on the applicant's experience in detection of wall thickness and detection of axially and circumferentially oriented flaws and its commitments to inspection of thimble and guide tubes (reference item 39 in Appendix A to this SER), the applicant has adequately described the parameters to be utilized during the inspections. This resolves Open Item B2.1.36-1(b).

<u>Detection of Aging Effects</u>. Thimble tube inspections are conducted using a methodology specified in a Ginna plant-specific procedure. This procedure requires the use of a Zetec MIZ-18 Multifrequency Eddy Current Testing System. These inspections indicate tube wear and tube wear rate. This is acceptable because eddy current examination has been successfully utilized to determine wall thickness and wear rate. The applicant had not identified whether the eddy current examination had been qualified to detect and size SCC. This was Open Item B2.1.36-1(c).

The applicant, in a letter dated December 9, 2003, has identified that the eddy current examination has been qualified to detect SCC but will not be capable of sizing SCC. Since sizing of SCC indications from eddy current data is somewhat unreliable, remediation criteria are based on detection. The remediation criteria are described above in "Parameters Monitored/Inspected." Based on the applicant's experience in detection of wall thickness and detection of axially and circumferentially oriented flaws and its commitments to inspection of thimble and guide tubes (reference item 39 in Appendix A to this SER), the applicant has adequately described the parameters to be utilized for detection of SCC and wear.
This resolves Open Item B2.1.36-1(c).

<u>Monitoring and Trending</u>. Based on the results of a plant-specific analysis, examination results are compared to an upper allowable limit of 65 percent through-wall wear.

Eddy current examinations performed in 1988, 1989, 1990, 1991, and 1992 provided a basis for establishing the wear rates, and thus the inspection intervals, for thimble tubes. Based on those results, the inspection frequency and acceptance criteria are as follows:

- previous indication 10 percent to less than 45 percent—every third refueling outage (approximately once every 4.2 years)

- previous indication 45 percent to less than 55 percent—every other refueling outage (approximately once every 3 years)

- previous indication 55 percent or greater—perform corrective action, if support plate wear is the suspected cause; for other indications, corrective action will be taken at 65 percent or greater; future inspection frequency will be every other or every third outage, as stated above

- previous inspection never exceeded 10 percent through-wall—no specified frequency; future inspections will be based on a Ginna periodic assessment

In response to RAI B2.1.36-1, in a letter dated May 13, 2003, the applicant provided the results from the inspections performed between 1988 and 1992. These inspections indicated that "none of the 36 thimble tubes have indicated a discernible increasing wear trend outside of the band of uncertainty (10 percent) assumed for the Eddy Current measurement technique" and that "the cumulative test results show that a conservatively predicted annual increase in wear is less than 5 percent. Therefore, for a tube whose inspection indicated less than 45 percent, there is adequate assurance that the 65 percent criterion would not be exceeded in four years." Similarly, for a tube with a previous indication between 45 percent and 55 percent, an inspection interval of 2 years would assure that the 65 percent criterion would not be exceeded.

This response also reported the results from the 1995 through 2002 inspections. Annual wear rates determined from inspections performed on all thimble tubes in 1995, 1997, and 1999 were within the predicted wear rate (5 percent) reported in 1993. Four tubes were replaced in 1999, three due to indications outside of the vessel and one (tube G-6) due to a wear indication which was sized at 59 percent through-wall.

All thimble tubes were again inspected in 2000. Wear rates determined from the 2000 inspections were within the 5 percent rate for all tubes except for the four tubes which had been replaced in 1999. Three of these four tubes exhibited wear indications ranging from 16 percent to 22 percent through-wall. One tube (G-6) exhibited a wear indication measuring 69 percent through-wall. Corrective action was taken on tube G-6 by repositioning and isolating the tube at the seal table. The unusual wear on this tube was attributed to the absence of chromium plating on the tube in the lower core plate region prone to wear.

All thimble tubes were again inspected during the refueling outage in April 2002. Tube G-6 was again replaced during this outage with a new chromium-plated tube. All other tubes exhibited wear rates within the predicted 5 percent rate except for one tube, B-6, which exhibited an increase in wall loss from 22 percent to 37 percent through-wall. Based on the inspection results through April 2002 and the applicant's actions to replace tubes that exhibit higher than predicted wear rate, the inspection methods and criteria described in the applicant's Thimble Tube Inspection Program are adequate for maintaining the integrity of the thimble tubes.

In response to RAI B2.1.36-1, in a letter dated May 13, 2003, the applicant also indicated that the thimble tube inspection will be performed every refueling outage during the period of extended operation unless inspections on a reduced frequency can be justified by engineering evaluation. However, the applicant had not identified the frequency and the basis for the frequency of inspection of SCC for thimble tubes and guide tubes. This was Open Item B2.1.36-1(d).

In a letter dated December 9, 2003, the applicant indicated the following:

> Eddy current inspections of all 36 thimble tubes for detection of SCC indications will be performed each refueling outage during the period of extended operation, unless inspections on a reduced frequency can be justified by engineering evaluation. As discussed in the response to RAI 3.2.2-1, the thimble tube inspections performed under the Thimble Tube Inspection Program are credited as the activities for managing cracking due to SCC of the guide tubes. The ID surface of the guide tubes is exposed to the same environment as the OD surface of the thimble tubes. Therefore, the condition of the thimble tubes (as determined by the results of the full-length eddy current inspections) is considered to be conservatively representative of the condition of the full length of the guide tubes, which are operated at a lower temperature.

The applicant's response identifies a frequency of inspection that will detect wear and SCC of the guide tubes before they lose their intended function. Therefore, the applicant has adequately addressed monitoring and trending. This resolves Open Item B2.1.36-1(d).

Acceptance Criteria. The acceptance criteria are provided in the preceding monitoring and trending discussion. The acceptance criteria are acceptable because the criteria allows tubes to be replaced prior to the wear, reducing the wall thickness to a size that could result in failure of the tube. However, the applicant had not identified the acceptance criteria for detection of SCC for thimble tubes and guide tubes. This was Open Item B2.1.36-1(e).

In a letter dated December 9, 2003, the applicant provided the following information with respect to the acceptance criteria for SCC:

> Any SCC indication in any thimble tube detected by eddy current examination requires remediation of the thimble tube, i.e., the thimble tube is isolated and/or replaced. The guide tube in which the "cracked" thimble tube resides would then be considered potentially cracked, and the guide tube would be inspected using an appropriate volumetric technique, such as eddy current testing (ECT) or ultrasonic testing (UT).
>
> The stainless steel fillet weld joining the BMI guide tube to the end of each BMI penetration has been inspected every outage by a remote visual (VT-2) technique for evidence of leakage. In addition, as committed to in the response to NRC Bulletin 2003-02, RG&E will perform a bare-metal examination of the RPV lower head penetrations each refueling outage until changes to the ASME Code or industry recommendations justify a change in the examination frequency. This inspection will include the stainless steel fillet weld joining each BMI guide tube to each penetration as well as the alloy 82/182 weld between the stainless steel safe-end and the lower head penetration nozzle, and will be VT-1 quality as defined in IWA 2210 of the ASME Section XI Code.

The applicant's acceptance criteria for SCC are acceptable because the applicant has provided remediation action to be taken on the guide tubes and will perform VT-1 quality examination of the stainless steel fillet weld joining each BMI guide tube to each penetration as well as the alloy 82/182 weld between the stainless steel safe-end and the lower head penetration nozzle, which will detect SCC prior to guide tubes losing their intended function. Therefore, the applicant has adequately addressed acceptance criteria. This resolves Open Item B2.1.36-1(e).

Operating Experience. Thimble tube wear in Westinghouse reactors was documented in NRC IN 87-44, "Thimble Tube Thinning in Westinghouse Reactors," and NRC Bulletin 88-09.

In response to these notifications, eddy current examination of thimble tubes was performed annually from 1988 to 1992 at Ginna. In 1990, thimble tube G-6 had indication of wear greater than 55 percent. Corrective action was taken by repositioning (moving worn areas away from the lower support plate by 1–2 inches) the tube. Three other thimble tubes had indications noted in the 1997 examination that resulted in the need for corrective action (Action Report 97-1889). All four thimble tubes were replaced during the 1999 refueling outage. One thimble had an indication of IGA. The conduit water was sampled, and analysis showed the presence of chlorides, fluorides, and sulfates in concentrations significantly above RCS water. These conduits were flushed during the thimble tube replacement. All other thimble tube conduits were flushed during the 2000 refueling outage. During the 2000 refueling outage, inspection of tube G-6 again indicated degradation due to flow-induced vibration. This tube was replaced with a chrome-plated tube during the 2002 refueling outage. Although this program has not eliminated wear of thimble tubes, it has been successful in identifying tubes that need to be replaced. It is acceptable because tubes are replaced before the wear reduces the wall thickness to a size that could result in failure of the tube.

3.1.2.3.7.3 Conclusions. On the basis of its review of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with GALL. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.1.2.3.8 Fatigue Monitoring Program

3.1.2.3.8.1 Summary of Technical Information in the Application. The applicant described its Fatigue Monitoring Program in Section B3.2 of the LRA. This program monitors loading cycles due to pressure and temperature transients for selected critical components. The applicant indicates that the program is consistent with GALL Program X.M1, "Metal Fatigue of Reactor Coolant Pressure Boundary." The purpose of the Fatigue Monitoring Program is to confirm that the number of cycles established by the analysis of record will not be exceeded before the end of the period of extended operation. The applicant indicated that the effects of the reactor coolant environment are considered through the evaluation of the seven component locations identified in NUREG/CR-6260 using the appropriate environmental fatigue factors.
The applicant stated that the Fatigue Monitoring Program includes reviews of both industry and plant-specific operating experience regarding fatigue cracking for applicability to Ginna.

3.1.2.3.8.2 Staff Evaluation. The LRA indicated that this AMP is consistent with GALL AMP X.M1. The staff confirmed the applicant's claim of consistency during the AMP audit. The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program. In addition, for Ginna, the staff determined whether the applicant properly applied the GALL program to its facility.

The applicant discussed the scope of the Fatigue Monitoring Program in Section B3.2.1 of the LRA. The scope of the program includes those components for which a cyclic or fatigue design basis exists. The program monitors loading cycles due to pressure and thermal transients for the selected critical components listed in Section B3.2.1 of the LRA. The staff confirmed that these selected critical components include the components identified in NUREG/CR-6260. The staff also reviewed the transients monitored by the program and the applicant's evaluation of the effects of the reactor environment. The staff evaluation of the transients monitored by the Fatigue Monitoring Program and the applicant's evaluation of the effects of the reactor water environment are discussed in Section 4.3 of this SER. The staff found that the applicant identified the thermal transients that are significant contributors to the design fatigue usage of RCS components and that the applicant had appropriately addressed the impact of the reactor water environment on the components identified in NUREG/CR-6260.

3.1.2.3.8.3 Conclusions. On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with GALL. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.1.2.4 Aging Management Review of Plant-Specific Components

This section includes reactor coolant (Class 1) components, reactor vessel, reactor vessel internals, pressurizer, steam generators, and reactor coolant (non-Class 1) components.

3.1.2.4.1 Reactor Coolant (Class 1)

3.1.2.4.1.1 Summary of Technical Information in the Application. The description of the reactor coolant (Class 1) can be found in Section 2.3.1.1 of the LRA. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3.1-1. This includes valves, pipes, elbows, fittings, RCP casings, RCP main flange, RCP lugs, thermal barrier heat exchanger tubing, orifices, reducers, and bolting. The components, aging effects, and AMPs are provided in LRA Tables 3.2-1 and 3.2-2.

Aging Effects

The LRA identified the following applicable aging effects for the reactor coolant (Class 1):

- cracking
- fatigue
- loss of fracture toughness due to thermal embrittlement
- loss of material
- loss of preload

Aging Management Programs

The LRA credited the following AMPs with managing the identified aging effects for the reactor coolant (Class 1):

- Water Chemistry Program (B2.1.37)
- Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program (B2.1.34)
- One-Time Inspection Program (B2.1.21)
- Bolting Integrity Program (B2.1.5)
- Boric Acid Corrosion Program (B2.1.6)
- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program (B2.1.2)

The applicant concluded that these AMPs will manage the effects of aging, such that the intended function of the reactor coolant (Class 1) will be maintained consistent with the CLB under all design loading conditions throughout the period of extended operation, as required by 10 CFR 54.21(a)(3). The applicant identified fatigue as a TLAA in Section 3.2 of the LRA that is applicable to reactor coolant (Class 1) components. This TLAA is described in Section 4.3 of the LRA and is discussed in Section 4.3 of this SER.

3.1.2.4.1.2 Staff Evaluation. This section provides the results of the staff's evaluation of the applicant's AMR for the aging effects and the AMPs credited for managing the aging effects in reactor coolant (Class 1). The staff also reviewed the applicable UFSAR Supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects

The LRA identified the following applicable aging effects for the reactor coolant (Class 1):

- loss of fracture toughness due to thermal embrittlement
- fatigue
- cracking
- loss of preload
- loss of material

The passive, long-lived components in the reactor coolant (Class 1) that are subject to an AMR are identified in LRA Tables 3.2-1 and 3.2-2. Table 3.2-1 includes components which were evaluated in the GALL Report. Components that the applicant indicates are consistent with GALL need no additional evaluation since GALL components and programs that are identified in GALL and require no further evaluation are acceptable to the staff. Components that require further evaluation are discussed in SER Section 3.1.2.2. The materials and environment for these components are identified in GALL.

Table 3.2-2 of the LRA includes components which were not evaluated in GALL. The table identifies the aging effects, materials, environment, and programs proposed for managing the aging effects. The staff has reviewed the information in this table and agrees that the applicant has identified the applicable aging effects because the aging effects are appropriate for these materials and environment and are consistent with nuclear power plant operating experiences.

On the basis of its review, the staff finds the applicant has identified the appropriate aging effects for the materials and environments associated with reactor coolant (Class 1).

Aging Management Programs

The applicant has credited the following AMPs with managing the aging effects described above for the reactor coolant (Class 1):

- Water Chemistry Program (B2.1.37)
- Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program (B2.1.34)
- One-Time Inspection Program (B2.1.21)
- Bolting Integrity Program (B2.1.5)
- Boric Acid Corrosion Program (B2.1.6)
- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program (B2.1.2)

As discussed above, components that the applicant indicates are consistent with GALL need no additional evaluation since GALL components and programs that are identified in GALL and require no further evaluation are acceptable to the staff. The components and programs that are used to manage the aging effects are discussed in SER Section 3.1.2.2.

Table 3.2-2 of the LRA includes components which were not evaluated in GALL. The table identifies the aging effects, materials, environment, and programs proposed for managing the aging effects. The staff has reviewed the information in this table and agrees that the applicant has identified AMPs to manage the aging effects identified in LRA Table 3.2-2.

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs with managing the aging effects for the materials and environments associated with reactor coolant (Class 1). In addition, the staff reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program and found it to be acceptable.

3.1.2.4.1.3 Conclusions. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and the AMPs credited for managing the aging effects for the reactor coolant (Class 1), such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement provides an adequate program description of the AMPs credited for managing aging in the reactor coolant (Class 1), as required by 10 CFR 54.21(d).

3.1.2.4.2 Reactor Vessel

3.1.2.4.2.1 Summary of Technical Information in the Application. The description of the reactor vessel can be found in Section 2.3.1.2 of the LRA. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3.1-2. This includes the RPV, O-ring leak monitor tubes, primary nozzle safe-ends, core support lugs, instrumentation tubes and safe-ends, BMI guide tubes, seal table fittings, ventilation shroud support ring, closure studs, nuts and washers, refueling seal ledge, and nozzle supports. The components, aging effects, and AMPs are provided in LRA Tables 3.2-1 and 3.2-2.

Aging Effects

The LRA identified the following applicable aging effects for the reactor vessel:

- cracking
- fatigue
- loss of fracture toughness due to neutron irradiation embrittlement
- loss of material
- loss of mechanical closure integrity due to stress relaxation
- change in dimension due to void swelling

Aging Management Programs

The LRA credited the following AMPs with managing the identified aging effects for the reactor vessel:

- Water Chemistry Program (B2.1.37)
- Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program (B2.1.34)
- Reactor Vessel Head Penetration Program (B2.1.26)
- Systems Monitoring Program (B2.1.33)
- Reactor Head Closure Studs Program (B2.1.25)
- Thimble Tube Inspection Program (B2.1.36)
- Reactor Vessel Surveillance Program (B2.1.28)
- Boric Acid Corrosion Program (B2.1.6)
- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program (B2.1.2)

The applicant concluded that these AMPs will manage the effects of aging, such that the intended function of the reactor vessel will be maintained consistent with the CLB under all design loading conditions throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.4.2.2 Staff Evaluation. This section provides the results of the staff's evaluation of the applicant's AMR for the aging effects and the AMPs credited with managing the aging effects in the reactor vessel. The staff also reviewed the applicable UFSAR Supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects

The LRA identified the following applicable aging effects for the reactor vessel:

- cracking
- fatigue
- loss of fracture toughness due to neutron irradiation embrittlement
- loss of material
- loss of mechanical closure integrity due to stress relaxation
- change in dimension due to void swelling

The passive, long-lived components in the reactor vessel that are subject to an AMR are identified in LRA Tables 3.2-1 and 3.2-2. LRA Table 3.2-1 includes components which were evaluated in the GALL Report. Components that the applicant indicates are consistent with GALL need no additional evaluation since GALL components and programs that are identified in GALL and require no further evaluation are acceptable to the staff. Components that require further evaluation are discussed in SER Section 3.1.2.2.

Table 3.2-2 of the LRA includes components which were not evaluated in GALL. The table identifies the aging effects, materials, environment, and programs proposed for managing the aging effects. The staff has reviewed the information in this table and agrees that the applicant has identified the applicable aging effects because the aging effects are appropriate for these materials and environment and are consistent with other nuclear plant operating experiences.

On the basis of its review, the staff finds the applicant has identified all of the aging effects for the materials and environments associated with the reactor vessel.

Aging Management Programs

The applicant has credited the following AMPs with managing the aging effects described above for the reactor vessel:

- Water Chemistry Program (B2.1.37)
- Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program (B2.1.34)
- Reactor Vessel Head Penetration Program (B2.1.26)
- Systems Monitoring Program (B2.1.33)

- Reactor Head Closure Studs Program (B2.1.25)
- Thimble Tube Inspection Program (B2.1.36)
- Reactor Vessel Surveillance Program (B2.1.28)
- Boric Acid Corrosion Program (B2.1.6)
- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program (B2.1.2)

As discussed above, components that the applicant indicates are consistent with GALL need no additional evaluation since GALL components and programs that are identified in GALL and require no further evaluation are acceptable to the staff. The components and programs that are used to manage the aging effect are discussed in SER Section 3.1.2.2.

Table 3.2-2 of the LRA includes components which were not evaluated in GALL. The table identifies the aging effects, materials, environment, and programs proposed for managing the aging effects. The staff has reviewed the information in this table and agrees that the applicant has identified AMPs to manage the aging effects identified in LRA Table 3.2-2.

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs with managing the aging effects for the materials and environments associated with the reactor vessel. In addition, the staff reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program and found it to be acceptable.

3.1.2.4.2.3 Conclusions. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and the AMPs credited with managing the aging effects for the reactor vessel, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement provides an adequate program description of the AMPs credited with managing aging in the reactor vessel, as required by 10 CFR 54.21(d).

3.1.2.4.3 Reactor Vessel Internals

3.1.2.4.3.1 Summary of Technical Information in the Application. The description of the reactor vessel internals can be found in Section 2.3.1.3 of the LRA. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3.1-3. The components, aging effects, and AMPs are provided in LRA Tables 3.2-1 and 3.2-2.

Aging Effects

The LRA identified the following applicable aging effects for the RVI:

- cracking
- fatigue
- loss of fracture toughness due to neutron irradiation embrittlement
- loss of material
- loss of preload

- change in dimension due to void swelling

Aging Management Programs

The LRA credited the following AMPs with managing the identified aging effects for the RVI:

- Water Chemistry Program (B2.1.37)
- Reactor Vessel Internals Program (B2.1.27)
- Thimble Tube Inspection Program (B2.1.36)
- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program (B2.1.2)

The applicant concluded that these AMPs will manage the effects of aging, such that the intended function of the RVI will be maintained consistent with the CLB under all design loading conditions throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.4.3.2 Staff Evaluation. This section provides the results of the staff's evaluation of the applicant's AMR for the aging effects and the AMPs credited with managing the aging effects in the RVI. The staff also reviewed the applicable UFSAR Supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects

The LRA identified the following applicable aging effects for the reactor vessel internals:

- cracking
- fatigue
- loss of fracture toughness due to neutron irradiation embrittlement
- loss of material
- loss of preload
- change in dimension due to void swelling

The passive, long-lived components in the RVI that are subject to an AMR are identified in LRA Tables 3.2-1 and 3.2-2. Table 3.2-1 includes components which were evaluated in the GALL Report. Components that the applicant indicates are consistent with GALL need no additional evaluation since GALL components and programs that are identified in GALL and require no further evaluation are acceptable to the staff. Components that require further evaluation are discussed in SER Section 3.1.2.2. The materials and environment for these components are identified in GALL.

Table 3.2-2 of the LRA includes components which were not evaluated in GALL. The table identifies the aging effects, materials, environment, and programs proposed for managing the aging effects. The staff has reviewed the information in this table and agrees that the applicant has identified the applicable aging effects because the aging effects are appropriate for these materials and environment and are consistent with nuclear power plant operating experiences.

On the basis of its review, the staff finds the applicant has identified all of the aging effects for the materials and environments associated with the RVI.

Aging Management Programs

The applicant has credited the following AMPs with managing the aging effects described above for the reactor vessel internals:

- Water Chemistry Program (B2.1.37)
- Reactor Vessel Internals Program (B2.1.27)
- Thimble Tube Inspection Program (B2.1.36)
- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program (B2.1.2)

As discussed above, components that the applicant indicates are consistent with GALL need no additional evaluation since GALL components and programs that are identified in GALL and require no further evaluation are acceptable to the staff. The components and programs that are used to manage the aging effect are discussed in SER Section 3.1.2.2.

Table 3.2-2 of the LRA includes components which were not evaluated in GALL. The table identifies the aging effects, materials, environment, and programs proposed for managing the aging effects. The staff has reviewed the information in this table and agrees that the applicant has identified AMPs to manage the aging effects identified in LRA Table 3.2-2, except for component 11, which is discussed below.

Component 11 in LRA Table 3.2.2

Section 3 of Table 3.2-2 of the application for renewed operating license, component 11 (secondary core support, diffuser plate, guide tube support pins, head vessel alignment pins, BMI columns and flux tubes, head cooling spray nozzles, upper instrumentation column, conduits, and supports), credits the Water Chemistry Control Program but does not credit the Inservice Inspection Program for monitoring SCC.

GALL Item IV B2.2.3 identifies rod cluster control assembly guide tube support pins constructed from stainless steel as being susceptible to crack initiation and growth, SCC, PWSCC, and IASCC. The GALL Report requires the use of a PWR vessel internals AMP in addition to a water chemistry AMP.

In response to RAI 3.2.2-3, in a letter dated May 13, 2003, the applicant indicated that the Reactor Vessel Internals Program, which is implemented by a combination of the Water Chemistry Control Program and ASME Section XI, Subsection IWB, was inadvertently omitted from Table 3.2-2 as an applicable AMP for components susceptible to SCC listed in line 11. The Reactor Vessel Internals Program will be applied to these components. Since the Reactor Vessel Internals Program provides for monitoring of cracking, the staff finds that the combination of the Reactor Vessel Internals Program and the Water Chemistry Control Program will be adequate for managing SCC for these components.

Component 12 in LRA Table 3.2.2

Section 3 of Table 3.2.2-2 of the application for renewed operating license, component 12 (upper and lower internals assembly, holddown spring, upper and lower support column bolts, and clevis insert bolts), identifies these components as being susceptible to loss of preload due to stress relaxation and credits the ASME Inservice Inspection Program for managing this aging effect. In the GALL Report, Items IV B2.1-d, IV B2.1-k, IV B2.5-h, and IV B2.5-i identify the upper internals assembly, holddown spring, lower internals assembly, and clevis insert bolts as being managed by ASME ISI and loose parts monitoring or neutron noise monitoring.

In response to RAI 3.2.2-4, in a letter dated May 13, 2003, the applicant indicated that neutron noise or loose parts monitoring methods are not employed at Ginna. Plant-specific operating experience demonstrates that ISIs performed under the ASME Section XI, Subsection IWB Inservice Inspection Program have been effective in managing loss of preload due to stress relaxation. These inspections have revealed no missing or loose reactor vessel or internals parts since the inception of plant operation. Based on acceptable plant-specific experience and the use of ASME Code Section XI Inservice Inspection Program to manage loss of preload due to stress relaxation, the staff agrees that loose parts monitoring is not necessary.

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs with managing the aging effects for the materials and environments associated with RVI.
In addition, the staff reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program and found it to be acceptable, as required by 10 CFR 54.21(d).

3.1.2.4.3.3 Conclusions. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and the AMPs credited with managing the aging effects for the RVI, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement provides an adequate program description of the AMPs credited with managing aging in the reactor vessel, as required by 10 CFR 54.21(d).

3.1.2.4.4 Pressurizer

3.1.2.4.4.1 Summary of Technical Information in the Application. The description of the pressurizer can be found in Section 2.3.1.4 of the LRA. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3.1-4. The components, aging effects, and AMPs are provided in LRA Tables 3.2-1 and 3.2-2.

Aging Effects

The LRA identified the following applicable aging effects for the pressurizer:

- cracking

- fatigue
- loss of material
- loss of preload

Aging Management Programs

The LRA credited the following AMPs with managing the identified aging effects for the pressurizer:

- Water Chemistry Program (B2.1.37)
- Boric Acid Corrosion Program (B2.1.6)
- Systems Monitoring Program (B2.1.33)
- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program (B2.1.2)
- Bolting Integrity Program (B2.1.5)

The applicant concluded that these AMPs will manage the effects of aging, such that the intended function of the pressurizer will be maintained consistent with the CLB under all design loading conditions throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.4.4.2 Staff Evaluation. This section provides the results of the staff's evaluation of the applicant's AMR for the aging effects and the AMPs credited with managing the aging effects in the pressurizer. The staff also reviewed the applicable UFSAR Supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects

The LRA identified the following applicable aging effects for the pressurizer:

- cracking
- fatigue
- loss of material
- loss of preload

The passive, long-lived components in the pressurizer that are subject to an AMR are identified in LRA Tables 3.2-1 and 3.2-2. Table 3.2-1 includes components which were evaluated in the GALL Report. Components that the applicant indicates are consistent with GALL need no additional evaluation since GALL components and programs that are identified in GALL and require no further evaluation are acceptable to the staff. Components that require further evaluation are discussed in SER Section 3.1.2.2. The materials and environment for these components are identified in GALL.

Table 3.2-2 of the LRA includes components which were not evaluated in GALL. The table identifies the aging effects, materials, environment, and programs proposed for managing the aging effects. The staff has reviewed the information in this table and agrees that the applicant has identified the applicable aging effects because the aging effects are appropriate for these materials and environment and are consistent with nuclear power plant operating experiences.

On the basis of its review, the staff finds the applicant has identified all of the aging effects for the materials and environments associated with the pressurizer.

Aging Management Programs

The applicant has credited the following AMPs with managing the aging effects described above for the pressurizer:

- Water Chemistry Program (B2.1.37)
- Boric Acid Corrosion Program (B2.1.6)
- Systems Monitoring Program (B2.1.33)
- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program (B2.1.2)
- Bolting Integrity Program (B2.1.5)

As discussed above, components that the applicant indicates are consistent with GALL need no additional evaluation since GALL components and programs that are identified in GALL and require no further evaluation, are acceptable to the staff. The components and programs that are used to manage the aging effects are discussed in SER Section 3.1.2.2.

Table 3.2-2 of the LRA includes components which were not evaluated in GALL. The table identifies the aging effects, materials, environment, and programs proposed for managing the aging effects. The staff has reviewed the information in this table and agrees that the applicant has identified AMPs to manage the aging effects identified in LRA Table 3.2-2, except for component 18, which is discussed below.

Component 18 in LRA Table 3.2.2

In Section 3 of Table 3.2.2-2 of the application for renewed operating license, component 18 (pressurizer manway cover) is identified as being constructed of carbon steel with a stainless steel disc insert and being susceptible to SCC. This table indicates that the Water Chemistry Control Program will be used to manage this aging effect.

Item IV C2.5-m in the GALL Report identifies pressurizer manway and flanges constructed from low-alloy steel with stainless steel cladding in a primary water environment as being susceptible to SCC. The GALL Report requires an ASME Section XI Inservice Inspection Program in addition to a Water Chemistry Control Program.

In response to RAI 3.2.2-5, in a letter dated May 13, 2003, the applicant indicated that the ASME Section XI Inservice Inspection Program was mistakenly omitted from this item in Table 3.2.2-2. To ensure that this program will be implemented for the pressurizer manway stainless steel insert, the applicant added performance of a visual and surface examination of the stainless steel insert to Section 7.2 of procedure GMM-47-01-05, "Removal and Installation of Pressurizer Manway Cover." The step will include reference to the Inspection Program and aging mechanism of SCC. Since the applicant proposes to include the pressurizer manway insert in its ASME Section XI Inservice Inspection Program and to utilize the Water Chemistry Control Program to mitigate SCC, the staff agrees that the proposed program will manage this aging effect.

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs with managing the aging effects for the materials and environments associated with the pressurizer. In addition, the staff reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program and found it to be acceptable, as required by 10 CFR 54.21(d).

3.1.2.4.4.3 Conclusions. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and the AMPs credited with managing the aging effects for the pressurizer, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement provides an adequate program description of the AMPs credited for managing aging in the pressurizer, as required by 10 CFR 54.21(d).

3.1.2.4.5 Steam Generators

3.1.2.4.5.1 Summary of Technical Information in the Application. The description of the steam generators can be found in Section 2.3.1.5 of the LRA. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3.1-5. The components, aging effects, and AMPs are provided in LRA Tables 3.2-1 and 3.2-2.

Aging Effects

The LRA identified the following applicable aging effects for the steam generators:

- cracking
- fatigue
- loss of material
- loss of preload

Aging Management Programs

The LRA credited the following AMPs with managing the identified aging effects for the steam generators:

- Water Chemistry Program (B2.1.37)
- Boric Acid Corrosion Program (B2.1.6)
- System Monitoring Program (B2.1.33)
- ASME Section XI, Subsections IWB, IWC and IWD Inservice Inspection Program (B2.1.2)
- Bolting Integrity Program (B2.1.5)

- Flow-Accelerated Corrosion Program (B2.1.15)
- Steam Generator Integrity Program (B2.1.31)

The applicant concluded that these AMPs will manage the effects of aging, such that the intended function of the steam generators will be maintained consistent with the CLB under all design loading conditions throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.4.5.2 Staff Evaluation. This section provides the results of the staff's evaluation of the applicant's AMR for the aging effects and the AMPs credited with managing the aging effects in the steam generators. The staff also reviewed the applicable UFSAR Supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects

The LRA identified the following applicable aging effects for the steam generators:

- cracking
- fatigue
- loss of material
- loss of preload

The passive, long-lived components in the steam generators that are subject to an AMR are identified in LRA Tables 3.2-1 and 3.2-2. Table 3.2-1 includes components which were evaluated in the GALL Report. Components that the applicant indicates are consistent with GALL need no additional evaluation since GALL components and programs that are identified in GALL and require no further evaluation are acceptable to the staff. Components that require further evaluation are discussed in SER Section 3.1.2.2. The materials and environment for these components are identified in GALL.

Table 3.2-2 of the LRA includes components which were not evaluated in GALL. The table identifies the aging effects, materials, environment, and programs proposed for managing the aging effects. The staff has reviewed the information in this table and agrees that the applicant has identified the applicable aging effects because the aging effects are appropriate for these materials and environment and are consistent with nuclear power plant operating experiences.

On the basis of its review, the staff finds the applicant has identified all of the aging effects for the materials and environments associated with the steam generators.

Aging Management Programs

The applicant has credited the following AMPs with managing the aging effects described above for the steam generators:

- Water Chemistry Program (B2.1.37)
- Boric Acid Corrosion Program (B2.1.6)

- Systems Monitoring Program (B2.1.33)
- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program (B2.1.2)
- Bolting Integrity Program (B2.1.5)
- Flow-Accelerated Corrosion Program (B2.1.15)
- Steam Generator Integrity Program (B2.1.31)

As discussed above, components that the applicant indicates are consistent with GALL need no additional evaluation since GALL components and programs that are identified in GALL and require no further evaluation are acceptable to the staff. The components and programs that are used to manage the aging effects are discussed in SER Section 3.1.2.2.

Table 3.2-2 of the LRA includes components which were not evaluated in GALL. The table identifies the aging effects, materials, environment, and programs proposed for managing the aging effects. The staff has reviewed the information in this table and agrees that the applicant has identified AMPs to manage the aging effects identified in LRA Table 3.2-2.

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs with managing the aging effects for the materials and environments associated with the steam generators. In addition, the staff reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program and found it to be acceptable, as required by 10 CFR 54.21(d).

3.1.2.4.5.3 Conclusions. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and the AMPs credited with managing the aging effects for the steam generators, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement provides an adequate program description of the AMPs credited for managing aging in the steam generators, as required by 10 CFR 54.21(d).

3.1.2.4.6 Reactor Coolant (Non-Class 1) Components

3.1.2.4.6.1 Summary of Technical Information in the Application. The description of the reactor coolant (non-Class 1) system can be found in Section 2.3.1.6 of the LRA. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3.1-6. The components, aging effects, and AMPs are provided in LRA Tables 3.2-1 and 3.2-2.

Aging Effects

The LRA identified the following applicable aging effects for the reactor coolant (non-Class 1) components:

- cracking
- fatigue
- loss of material
- loss of preload

- loss of heat transfer due to particulate and biological fouling

Aging Management Programs

The LRA credited the following AMPs with managing the identified aging effects for the reactor coolant (non-Class 1) components:

- Water Chemistry Program (B2.1.37)
- Boric Acid Corrosion Program (B2.1.6)
- Systems Monitoring Program (B2.1.33)
- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program (B2.1.2)
- Bolting Integrity Program (B2.1.5)
- Periodic Surveillance and Preventive Maintenance Program (B2.1.23)
- One-Time Inspection Program (B2.1.21)

The applicant concluded that these AMPs will manage the effects of aging, such that the intended function of the reactor coolant (non-Class 1) components will be maintained consistent with the CLB under all design loading conditions throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.4.6.2 Staff Evaluation. This section provides the results of the staff's evaluation of the applicant's AMR for the aging effects and the AMPs credited with managing the aging effects in the reactor coolant (non-Class 1). The staff also reviewed the applicable UFSAR Supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects

The LRA identified the following applicable aging effects for the reactor coolant (non-Class 1) components:

- cracking
- fatigue
- loss of material
- loss of preload
- loss of heat transfer due to particulate and biological fouling

The passive, long-lived components in the reactor coolant (non-Class 1) systems that are subject to an AMR are identified in LRA Tables 3.2-1 and 3.2-2. Table 3.2-1 includes components which were evaluated in the GALL Report. Components that the applicant indicates are consistent with GALL need no additional evaluation since GALL components and programs that are identified in GALL and require no further evaluation are acceptable to the staff. Components that require further evaluation are discussed in SER Section 3.1.2.2. The materials and environment for these components are identified in GALL.

Table 3.2-2 of the LRA includes components which were not evaluated in GALL. The table identifies the aging effects, materials, environment, and programs proposed for managing the aging effects. The staff has reviewed the information in this table and agrees that the applicant has identified the applicable aging effects because the aging effects are appropriate for these materials and environment and are consistent with nuclear power plant operating experiences.

On the basis of its review, the staff finds the applicant has identified all of the aging effects for the materials and environments associated with the reactor coolant (non-Class 1) systems.

Aging Management Programs

The applicant has credited the following AMPs with managing the aging effects described above for the reactor coolant (non-Class 1) components:

- Water Chemistry Program (B2.1.37)
- Boric Acid Corrosion Program (B2.1.6)
- System Monitoring Program (B2.1.33)
- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program (B2.1.2)
- Bolting Integrity Program (B2.1.5)
- Periodic Surveillance and Preventive Maintenance Program (B2.1.23)
- One-Time Inspection Program (B2.1.21)

As discussed above, components that the applicant indicates are consistent with GALL need no additional evaluation since GALL components and programs that are identified in GALL and require no further evaluation are acceptable to the staff. The components and programs that are used to manage the aging effects are discussed in SER Section 3.1.2.2.

Table 3.2-2 of the LRA includes components which were not evaluated in GALL. The table identifies the aging effects, materials, environment, and programs proposed for managing the aging effects. The staff has reviewed the information in this table and agrees that the applicant has identified AMPs to manage the aging effects identified in LRA Table 3.2-2.

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs with managing the aging effects for the materials and environments associated with the reactor coolant (non-Class 1) components. In addition, the staff reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program and found it to be acceptable, as required by 10 CFR 54.21(d).

3.1.2.4.6.3 Conclusions. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects, and the AMPs credited with managing the aging effects for the reactor coolant (non-Class 1), such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement provides an adequate program description of the AMPs credited for managing aging in the reactor coolant (non-Class 1), as required by 10 CFR 54.21(d).

3.1.3 Evaluation Findings

The staff has reviewed the information in Section 3.2 of the LRA. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and the AMPs credited with managing the aging effects for the reactor system, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.29(a). The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement provides an adequate program description of the AMPs credited for managing aging effects, as required by 10 CFR 54.21(d).

3.2 Engineered Safety Features Systems

This section addresses the aging management of the components of the ESF systems group. The systems that make up the ESF systems group are described in the SER sections listed below:

- Safety Injection (2.3.2.1)
- Containment Spray (2.3.2.2)
- Residual Heat Removal (2.3.2.3)
- Containment Hydrogen Detectors and Recombiners (2.3.2.4)
- Containment Isolation Components (2.3.2.5)

As discussed in Section 3.0.1 of this SER, the components in each of these ESF systems are included in one of two LRA tables. Table 3.3-1 consists of ESF systems components that are evaluated in the GALL Report, and Table 3.3-2 consists of ESF systems components that are not evaluated in the GALL Report.

3.2.1 Summary of Technical Information in the Application

In LRA Section 3.3, the applicant described its AMRs for the ESF systems group at Ginna. The description of the systems that compose the ESF systems group can be found in LRA Section 2.3.2. The passive, long-lived components in these systems that are subject to an AMR are identified in LRA Tables 2.3.2-1 through 2.3.2-5.

The applicant's AMRs included an evaluation of plant-specific and industry operating experience. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify aging effects that require management. These reviews concluded that the aging effects requiring management based on Ginna operating experience were consistent with aging effects identified in GALL.

The applicant's review of industry operating experience included a review of operating experience through 2002. The results of this review concluded that aging effects requiring management based on industry operating experience were consistent with aging effects identified in GALL.

The applicant's ongoing review of plant-specific and industry-wide operating experience is conducted in accordance with the Ginna Operating Experience Program.

3.2.2 Staff Evaluation

In Section 3.3 of the LRA, the applicant describes its AMR for the ESF systems. The staff reviewed LRA Section 3.3 to determine whether the applicant has provided sufficient information to demonstrate that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the period of extended operation, in accordance with the requirements of 10 CFR 54.21(a)(3), for the ESF system components that are determined to be within the scope of license renewal and subject to an AMR.

The applicant referenced the GALL Report in its AMR. The staff has previously evaluated the adequacy of the aging management of ESF system components for license renewal as documented in the GALL Report. Thus, the staff did not repeat its review of the matters described in the GALL Report, except to ensure that the material presented in the LRA was applicable and to verify that the applicant had identified the appropriate programs as described and evaluated in the GALL Report. The staff evaluated those aging management issues recommended for further evaluation in the GALL Report. The staff also reviewed aging management information submitted by the applicant that was different from that in the GALL Report or was not addressed in the GALL Report. Finally, the staff reviewed the UFSAR Supplement to ensure that it provided an adequate description of the programs credited with managing aging for the ESF systems components.

In LRA Section 3.3, the applicant provided brief descriptions of the ESF systems and summarized the results of its AMR of the ESF systems at Ginna.

Table 3.2-1 below provides a summary of the staff's evaluation of components, aging effects/mechanisms, and AMPs listed in LRA Section 3.3 that are addressed in the GALL Report.

Table 3.2-1 Staff Evaluation for Ginna Engineered Safety Features System Components in the GALL Report

Component Group	Aging Effect/Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Piping, fittings, and valves in emergency core cooling system	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	TLAA	Consistent with GALL. GALL recommends further evaluation (see Section 3.2.2.2.1 below)
Piping, fittings, pumps, and valves in emergency core cooling system	Loss of material due to general corrosion	Water Chemistry and One-Time Inspection	N/A	BWR

Component Group	Aging Effect/Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Components in containment spray (PWR only), standby gas treatment (BWR only), containment isolation, and emergency core cooling systems	Loss of material due to general corrosion	Plant specific	None	Not applicable to Ginna. GALL recommends further evaluation (see Section 3.2.2.2.2 below)
Piping, fittings, pumps, and valves in emergency core cooling system	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	N/A	BWR
Components in containment spray (PWR only), standby gas treatment (BWR only), containment isolation, and emergency core cooling systems	Loss of material due to pitting and crevice corrosion	Plant specific	One-Time Inspection and Systems Monitoring Programs	Consistent with GALL. GALL recommends further evaluation (see Section 3.2.2.2.3 below)
Containment isolation valves and associated piping	Loss of material due to microbiologically influenced corrosion	Plant specific	Periodic Surveillance and Preventive Maintenance Programs	Consistent with GALL. GALL recommends further evaluation (see Section 3.2.2.2.4 below)
Seals in standby gas treatment system	Changes in properties due to elastomer degradation	Plant specific	N/A	BWR
High-pressure safety injection (charging) pump miniflow orifice	Loss of material due to erosion	Plant specific	None	Not applicable to Ginna (see Section 3.2.2.2.5 below)
Drywell and suppression chamber spray system nozzles and flow orifices	Plugging of nozzles and flow orifices due to general corrosion	Plant specific	N/A	BWR
Piping and fittings of CASS in emergency core cooling system	Loss of fracture toughness due to thermal aging embrittlement	Thermal Aging Embrittlement CASS	None	Not applicable to Ginna
Components serviced by open-cycle cooling system	Local loss of material due to corrosion and/or buildup of deposit due to biofouling	Open-Cycle Cooling Water System	None	Not applicable at Ginna
Components serviced by closed-cycle cooling system	Loss of material due to general, pitting, and crevice corrosion	Closed-Cycle Cooling Water System	Closed-Cycle (Component) Cooling Water System Program	Consistent with GALL (see Section 3.2.2.1 below)
Emergency core cooling system valves and lines to and from HPCI and RCIC pump turbines	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion	N/A	BWR

Component Group	Aging Effect/Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Pumps, valves, piping, and fittings in containment spray and emergency core cooling systems	Crack initiation and growth due to SCC	Water Chemistry	Water Chemistry Control and One-Time Inspection Programs	Consistent with GALL (see Section 3.2.2.1 below)
Pumps, valves, piping, and fittings in emergency core cooling systems	Crack initiation and growth due to SCC and IGSCC	Water Chemistry and BWR Stress-Corrosion Cracking	N/A	BWR
Carbon steel components	Loss of material due to boric acid corrosion	Boric Acid Corrosion	Boric Acid Corrosion Program	Consistent with GALL (see Section 3.2.2.1 below)
Closure bolting in high-pressure or high-temperature systems	Loss of material due to general corrosion, loss of preload due to stress relaxation, and crack initiation and growth due to cyclic loading or SCC	Bolting Integrity	Bolting Integrity Program	Consistent with GALL (see Section 3.2.2.1 below)

The staff's review of the ESF systems for the Ginna LRA is contained within four sections of this SER. Section 3.2.2.1 is the staff review of components in the ESF systems that the applicant indicates are consistent with GALL and do not require further evaluation. Section 3.2.2.2 is the staff review of components in the ESF systems that the applicant indicates are consistent with GALL and for which GALL recommends further evaluation. Section 3.2.2.3 is the staff evaluation of AMPs that are specific to the ESF systems. Section 3.2.2.4 contains an evaluation of the adequacy of aging management for components in each system in the ESF systems group and includes an evaluation of components in the ESF systems that the applicant indicates are not in GALL.

3.2.2.1 Aging Management Evaluations in the GALL Report That Are Relied on for License Renewal, Which Do Not Require Further Evaluation

For component groups evaluated in GALL for which the applicant has claimed consistency with GALL and for which GALL does not recommend further evaluation, the staff sampled components in these groups to determine whether the plant-specific components contained in these GALL component groups were bounded by the GALL evaluation. The staff also sampled component groups to determine whether the applicant had properly identified those component groups in GALL that were not applicable to its plant. The staff identified several areas where additional information or clarification was needed. The staff's evaluation of the applicant's responses to those RAIs is included in Section 3.2.2.4 of this SER.

On the basis of its review, the staff has verified the applicant's claim of consistency with the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 50.21(a)(3).

3.2.2.2 Aging Management Evaluations in the GALL Report That Are Relied on for License Renewal, for Which GALL Recommends Further Evaluation

For component groups evaluated in GALL for which the applicant has claimed consistency with GALL and for which GALL recommends further evaluation, the staff reviewed the applicant's evaluation to determine whether it adequately addressed the issues for which GALL recommended further evaluation. In addition, the staff sampled components in these groups to determine whether the plant-specific components contained in these GALL component groups were bounded by the GALL evaluation.

The GALL Report indicates that further evaluation should be performed in the areas discussed in the following sections.

3.2.2.2.1 Cumulative Fatigue Damage

The GALL Report identifies fatigue as a TLAA as defined in 10 CFR 54.3. All TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The staff reviewed the evaluation of this TLAA in Section 4.3 of this SER, following the guidance in Section 4.3 of the SRP-LR.

The applicant indicated that all TLAAs were evaluated in the RCS section of the LRA, and none appeared in the ESF section. Safety injection nozzles are designated Class 1 and were included in the RCS section. The applicant discusses the TLAA in Section 4.3 of the LRA, "Metal Fatigue." This TLAA is evaluated in Section 4.3 of this SER.

On the basis of its review, the staff finds that the applicant appropriately evaluated AMR results involving management of cumulative fatigue damage for components in the applicable ESF systems, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with the GALL Report, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2.2 Loss of Material Due to General Corrosion

Loss of material due to general corrosion could occur in the containment spray system header and spray nozzle components and the external surfaces of PWR carbon steel components. The GALL Report recommends further evaluation on a plant-specific basis to ensure that the aging effect is adequately managed. The staff reviewed the applicant's proposed programs to ensure that an adequate program will be in place for the management of general corrosion of these components.

The applicant indicated in LRA Table 3.3-1, line 2, that the carbon steel containment spray headers and spray nozzles and the associated components, in air environments, as identified in GALL Items V.A.2-a and V.A.5-a, are not applicable to components in the Ginna containment spray system. The applicant also stated that containment isolation components identified in

Item V.C.1-a, such as valve body and bonnet, and pipe penetrations, are included in the containment isolation valves and associated piping entry in LRA Table 3.3-1, line 4. This component grouping is evaluated in Section 3.2.2.2.4 of this SER.

3.2.2.2.3 Local Loss of Material Due to Pitting and Crevice Corrosion

Local loss of material from pitting and crevice corrosion could occur in containment spray components, containment isolation valves and associated piping, and buried portions of the refueling water tank external surface. The GALL Report recommends further evaluation to ensure that the aging effect is adequately managed. The staff reviewed the applicant's proposed programs to ensure that an adequate program will be in place for the management of local loss of material due to pitting and crevice corrosion of these components.

In LRA Table 3.3-1, line 3, the applicant credited its One-Time Inspection Program with managing the loss of material due to pitting and crevice corrosion for containment isolation components and the refueling water storage tank bottom. The applicant also credited the Systems Monitoring Program with managing all other applicable aging effects. The staff's review of these two AMPs is documented in Sections 3.0.3.7 and 3.0.3.11, respectively, of this SER.

The staff reviewed the applicant's One-Time Inspection Program to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation. The staff verified that the applicant's one-time inspection of selected components is performed at susceptible locations, based on severity of conditions, time of service, and the lowest design margin. The staff also verified that the proposed inspection would be performed using techniques similar to ASME Code and ASTM standards, including visual, ultrasonic, and surface techniques. The staff concludes that the AMP is sufficient to manage the identified aging effect of loss of material.

On the basis of its review, the staff finds that the applicant appropriately evaluated AMR results involving management of local loss of material due to pitting and crevice corrosion for components in the applicable ESF systems, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with the GALL Report, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2.4 Local Loss of Material Due to Microbiologically Influenced Corrosion

Local loss of material due to MIC could occur in PWR containment isolation valves and associated piping in systems that are not addressed in other chapters of the GALL Report. The GALL Report recommends further evaluation to ensure that the aging effect is adequately managed. The staff reviewed the applicant's proposed programs to ensure that an adequate program will be in place for the management of local loss of material due to MIC of the containment isolation barriers.

In LRA Table 3.3-1, line 4, the applicant stated that, for containment isolation components such as valves and pipe penetrations, the aging effect of loss of material due to MIC is managed by the plant-specific Periodic Surveillance and Preventive Maintenance Program. The staff review of this AMP is documented in Section 3.0.3.8 of this SER.

The staff reviewed the applicant's proposed program to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation. The staff's review verified that the applicant's AMP is sufficient to manage the identified aging effect of loss of material.

On the basis of its review, the staff finds that the applicant appropriately evaluated AMR results involving management of local loss of material due to MIC for components in the applicable ESF systems, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with the GALL Report, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2.5 Local Loss of Material Due to Erosion

Local loss of material due to erosion could occur in the high-pressure safety injection pump miniflow orifice. This aging mechanism and effect will apply only to pumps that are normally used as charging pumps in the chemical and volume control systems. The GALL Report recommends further evaluation to ensure that the aging effect is adequately managed for these components. The staff reviewed the applicant's proposed programs to ensure that an adequate program will be in place to manage this aging effect.

The applicant stated in LRA Table 3.3-1, line 5, that the high-pressure safety injection (charging) pump miniflow orifice, as identified in GALL, is not applicable to Ginna. Since this GALL component grouping does not exist in Ginna, loss of material due to erosion is not a relevant aging effect requiring management. Therefore, the staff agrees that no AMP is required.

3.2.2.2.6 Conclusions

The staff has reviewed the applicant's evaluation of the issues for which GALL recommends further evaluation for components in the ESF systems. On the basis of its review, the staff finds that the applicant has provided sufficient information to demonstrate that the issues for which the GALL Report recommends further evaluation have been adequately addressed and that there is reasonable assurance that the subject aging effects will be adequately managed for the period of extended operation.

3.2.2.3 Aging Management Programs for Engineered Safety Features Systems Components

In SER Section 3.2.2.1, the staff evaluated the applicant's conformance with the aging management recommended by GALL for ESF systems. In SER Section 3.2.2.2, the staff reviewed the applicant's evaluation of the issues for which GALL recommends further evaluation. In this SER section, the staff presents its evaluation of the programs used by the applicant to manage the aging of the component groups within the ESF systems.

The applicant credits seven AMPs with managing the aging effects associated with components in the ESF systems. All seven AMPs are credited with managing aging for components in other system groups (common AMPs). The staff's evaluation of the common AMPs that are credited with managing aging in ESF system components is provided in Section 3.0.3 of this SER. The common AMPs credited for ESF components are as follows:

- Water Chemistry Control Program (3.0.3.1)
- Bolting Integrity Program (3.0.3.3)
- Boric Acid Corrosion Prevention Program (3.0.3.4)
- Closed-Cycle (Component) Cooling Water System Program (3.0.3.5)
- Periodic Surveillance and Preventive Maintenance Program (3.0.3.8)
- One-Time Inspection Program (3.0.3.7)
- Systems Monitoring Program (3.0.3.11)

There are no AMPs that are specific to ESF systems.

3.2.2.4 Aging Management Review of Plant-Specific Engineered Safety Features Systems Components

In this section of the SER, the staff presents its review of the applicant's AMR for specific components within the ESF systems. To perform its evaluation, the staff reviewed the components listed in LRA Tables 2.3.2-1 through 2.3.2-5 to determine whether the applicant had properly identified the applicable aging effects and the AMPs needed to adequately manage these aging effects. This portion of the staff's review involved identification of the aging effects for each ESF component, ensuring that each aging effect was evaluated in the appropriate LRA AMR table in Section 3 and that management of the aging effect was captured in the appropriate AMP. The results of the staff's review are provided below.

3.2.2.4.1 Safety Injection System

3.2.2.4.1.1 Summary of Technical Information in the Application. The description of the safety injection system can be found in Section 2.3.2.1 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3.2-1. The components, aging effects, and AMPs are provided in LRA Tables 3.3-1 and 3.3-2.

Aging Effects

Components of the safety injection system are described in LRA Section 2.3.2.1 as being within the scope of license renewal and subject to an AMR. Table 2.3.2-1 of the LRA lists individual components of the system including accumulator, carbon steel components, fasteners (bolting), flow element, heat exchanger, indicator, orifice, pipe, pump casing, tank, and valve body.

Stainless steel and CASS components in treated water—borated less than 140 °F are identified as being subject to loss of material. Stainless steel and CASS components in treated water—borated greater than 140 °F are identified as being subject to loss of material and cracking due to SCC. Stainless steel tank bottom sitting on concrete is identified as being subject to loss of material. No aging effects are identified for stainless steel and CASS components in air and gas, containment, and indoor not-air-conditioned environments. No aging effects are identified for stainless steel fasteners (bolting) exposed to borated water leaks from other plant systems.

Carbon and low-alloy steel components in containment air are identified as being subject to loss of material. Carbon steel and low-alloy steel fasteners (bolting) in indoor not-air-conditioned environments are identified as subject to loss of material and loss of preload due to stress relaxation. Carbon steel components, including fasteners (bolting), in borated water leaks environments are identified as being subject to loss of material. Since there are no bolts with a specified minimum yield strength greater than 150 ksi in the ESF systems, SCC is not an applicable aging effect/mechanism.

Cast iron and nickel alloy heat exchanger components are identified as being subject to loss of material when exposed to oil and fuel oil, raw water, treated water—borated less than 140 °F, and treated water—other environments. These heat exchanger components are also subject to loss of heat transfer when exposed to the same environments. Cast iron components in indoor not-air- conditioned environments are identified as being subject to loss of material.

Aging Management Programs

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

- Bolting Integrity Program
- Water Chemistry Control Program
- Boric Acid Corrosion Prevention Program
- Periodic Surveillance and Preventive Maintenance Program
- One-Time Inspection Program
- System Monitoring Program
- Closed-Cycle (Component) Cooling Water System Program

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

3.2.2.4.1.2 Staff Evaluation

Aging Effects

The staff reviewed the information in LRA Tables 2.3.2-1, 3.3-1, and 3.3-2 for the safety injection system. During its review, the staff determined that additional information was needed to complete its review.

In LRA Table 3.3-1, line 7, the applicant stated that the combinations of components, materials, and environments identified in Items V.A.6-a, V.A.6-b, V.D1.6-b, and V.D1.6-c of GALL are not applicable at Ginna. These GALL items address carbon and stainless steel heat exchangers and associated components in containment spray and ECCS systems in chemically treated borated water and raw water environments. In RAI 3.3-1, the staff asked the applicant to discuss how AMR is performed for the above heat exchangers and their associated components at Ginna. By letter dated May 23, 2003, the applicant stated that the containment spray and ECCS systems at Ginna have no heat exchangers that are provided cooling by the service water (open-cycle cooling water) system other than the safety injection pump thrust bearing coolers. These coolers are made of cast iron with a single, once-through passage of service water providing cooling to the oil supplying the thrust bearing (nonforced fed oil supply). Neither the material of construction (cast iron) nor the environment (oil) is covered by GALL. The applicant stated that these coolers are included in LRA Table 2.3.2-1 under the component group of heat exchanger, and are linked to Table 3.3-2, lines 23–27, for AMR results. Based on its review of the information provided in Table 3.3-2, lines 23–27, the staff finds the applicant has properly addressed the AMR for the containment spray and ECCS systems heat exchangers. Therefore, the staff considers RAI 3.3-1 closed.

In LRA Table 3.3-2, line 11, the applicant identified no aging effects requiring management for the stainless steel fasteners (bolting) in borated water leakage environments. In RAI 3.3-3x2, the staff requested the applicant to provide the basis for such determination. By letter dated May 23, 2003, the applicant stated that the technical basis for identifying that there are no aging effects requiring management for stainless steel fasteners exposed to borated water leaks is found in EPRI TR-101108, “Boric Acid Corrosion Evaluation Program, Phase 1—Task 1 Report,” and in EPRI TR-104748, “Boric Acid Corrosion Guidebook.” These documents contain compilations of pertinent industry experience and summaries of corrosion test data which identify stainless steel and nickel-base alloys as alternative fastener materials which display excellent resistance to corrosion from borated water leaks. The staff considers the applicant’s reference of the industry’s experience to be acceptable. Therefore, the staff considers the response acceptable.

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 safety injection system structures and components with the environments described in LRA Tables 2.3.2-1, 3.3-1, and 3.3-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the safety injection system.

Aging Management Programs

The applicant credited the following AMPs with managing the aging effects in the safety injection system:

- Water Chemistry Control Program (3.0.3.1)
- Bolting Integrity Program (3.0.3.3)

- Boric Acid Corrosion Prevention Program (3.0.3.4)
- Closed-Cycle (Component) Cooling Water System Program (3.0.3.5)
- One-Time Inspection Program (3.0.3.7)
- Periodic Surveillance and Preventive Maintenance Program (3.0.3.8)
- Systems Monitoring Program (3.0.3.11)

These AMPs are credited with managing the aging effects of several components in other structures and systems and, therefore, are 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 the SER sections given in parentheses above.

After evaluating the applicant's AMR for each of the components in the safety injection system, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects. For those components identified in Table 3.3-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in LRA Table 3.3-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effects.

In LRA Table 3.3-2, line 25, the One-Time Inspection Program is credited with managing loss of material for the cast iron safety injection heat exchanger in raw water environments.
In RAI 3.3-2, the staff requested the applicant to provide the basis that, for the above material/environment combination, the One-Time Inspection Program alone is adequate to ensure that the aging effect will be effectively managed during the extended period of operation. By letter dated May 23, 2003, the applicant stated that a review of Ginna specific operating experience reveals that no age-related degradation of this material/environment grouping has been found. The applicant stated that the raw water environment (service water system) at Ginna is supplied from Lake Ontario (fresh water), which is not an aggressive environment. Numerous inspections of service water pump casings made of the same material have identified no age-related degradation. The applicant stated that the one-time inspection will be performed on each safety injection pump outboard bearing cooler. The inspection will be completed prior to the end of the initial operating license. The staff finds the applicant's One-Time Inspection Program to be acceptable on the basis that (1) the raw water environment at Ginna is not an aggressive environment, (2) no age-related degradation has been found for the service water pump casings made of similar material, and (3) based upon the results of the inspection, an engineering evaluation will be performed to determine if additional aging management activities will be required.

In LRA Table 3.3-2, line 28, the Water Chemistry Control Program is utilized to manage the aging effect of loss of heat transfer for the nickel alloy heat exchanger from exposure to treated water—borated less than 140 °F. In RAI 3.3-3, the staff requested the applicant to provide the basis for not supplementing with a one-time inspection to verify the effectiveness of the Water Chemistry Control Program. By letter dated May 23, 2003, the applicant stated that a one-time inspection is included in Table 3.3-2, line 30, for the nickel alloy heat exchanger components. This is acceptable to the staff because the inspection will verify the effectiveness of the water chemistry controls.

Based on its review of the information provided in the LRA, the staff concludes that the above identified AMPs will effectively manage the aging effects for the components of the safety injection system.

3.2.2.4.1.3 Conclusions. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and the AMPs credited with managing the aging effects for the safety injection system, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

3.2.2.4.2 Containment Spray System

3.2.2.4.2.1 Summary of Technical Information in the Application. The description of the containment spray system can be found in Section 2.3.2.2 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3.2-2. The components, aging effects, and AMPs are provided in LRA Tables 3.3-1 and 3.3-2.

Aging Effects

Components of the containment spray system are described in LRA Section 2.3.2.2 as being within the scope of license renewal and subject to an AMR. Table 2.3.2-2 of the LRA lists individual components of the system including carbon steel components, eductor, fasteners (bolting), flow nozzles, heat exchanger, indicator, orifice, pipe, pump casing, tank, transmitter, and valve body.

Stainless steel components are identified as being subject to loss of material when exposed to treated water—borated less than 140 °F, treated water—other, and treated water—other (stagnant) environments. Components made of CASS are identified as being subject to loss of material when exposed to treated water—borated less than 140 °F, and treated water—other (stagnant) environments. No aging effects are identified for stainless steel components in air and gas, indoor not-air-conditioned, and containment environments. No aging effects are identified for CASS steel components in air and gas and indoor not-air-conditioned environments. No aging effects are identified for stainless steel fasteners (bolting) in borated water leaks from other plant systems.

Carbon/low-alloy steel fasteners (bolting) in borated water leaks are identified as being subject to loss of material. Carbon/low-alloy steel fasteners (bolting) in indoor not-air-conditioned environments are identified as being subject to loss of material and loss of preload due to stress relaxation. Since there are no bolts with a specified minimum yield strength greater than 150 ksi in the ESF systems, SCC is not an applicable aging effect/mechanism.

Cast iron components in treated water—other and indoor not-air-conditioned environments are identified as being subject to loss of material.

Aging Management Programs

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

- Bolting Integrity Program
- Water Chemistry Control Program
- Boric Acid Corrosion Prevention Program
- One-Time Inspection Program
- Systems Monitoring Program
- Closed-Cycle (Component) Cooling Water System Program

A description of these AMPs is provided in Appendix B of the LRA.

3.2.2.4.2.2 Staff Evaluation

Aging Effects

The staff reviewed the information in LRA Tables 2.3.2-2, 3.3-1, and 3.3-2 for the containment spray system. During its review, the staff determined that additional information was needed to complete its review.

In RAI 3.3-1, the staff asked the applicant to discuss how the AMR is performed for the heat exchangers and their associated components in the containment spray and ECCS systems. The staff's discussion of this RAI and its resolution by the applicant are provided in Section 3.2.2.4.1.2 of this SER.

In RAI 3.3-3x2, the staff requested the applicant to provide its basis for determining in LRA Table 3.3-2, line 11, that there are no aging effects requiring management for the stainless steel fasteners (bolting) in the borated water leakages environments. The staff's discussion of this RAI and its resolution by the applicant are provided in Section 3.2.2.4.1.2 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 responses to the above RAIs, the staff finds that the aging effects that result from contact of the containment spray system structures and components to the environments described in LRA Tables 2.3.2-2, 3.3-1, and 3.3-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the containment spray system.

Aging Management Programs

The applicant credited the following AMPs with managing the aging effects in the containment spray system:

- Water Chemistry Control Program (3.0.3.1)
- Bolting Integrity Program (3.0.3.3)

- Boric Acid Corrosion Prevention Program (3.0.3.4)
- Closed-Cycle (Component) Cooling Water System Program (3.0.3.5)
- One-Time Inspection Program (3.0.3.7)
- Systems Monitoring Program (3.0.3.11)

These AMPs are credited with managing the aging effects of several components in other structures and systems and, therefore, are 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 the SER sections given in parentheses above.

After evaluating the applicant's AMR for each of the components in the containment spray system, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects. For those components identified in Table 3.3-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in LRA Table 3.3-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effects.

Based on its review of the information provided in the LRA, the staff concludes that the above identified AMPs will effectively manage the aging effects for the components of the containment spray system.

3.2.2.4.2.3 <u>Conclusions.</u> On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and the AMPs credited with managing the aging effects for the containment spray system, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

3.2.2.4.3 Residual Heat Removal System

3.2.2.4.3.1 <u>Summary of Technical Information in the Application.</u> The RHR system is described in Section 2.3.2.3 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3.2-3. The components, aging effects, and AMPs are provided in LRA Tables 3.3-1 and 3.3-2.

<u>Aging Effects</u>

Components of the RHR system are described in LRA Section 2.3.2.3 as being within the scope of license renewal and subject to an AMR. Table 2.3.2-3 of the LRA lists individual components of the system including carbon steel components, fasteners (bolting), flow element, heat exchanger, indicator, orifice, pipe, pump casing, switch, temperature element, and valve body.

Stainless steel components are identified as being subject to loss of material when exposed to treated water—borated less than 140 °F and treated water other environments. Stainless steel components in treated water—borated less than 140 °F environments are identified as being subject to loss of material and cracking due to SCC. Stainless steel heat exchanger components are identified as being subject to loss of heat transfer when exposed to treated water—borated less than 140 °F and treated water—other environments. Cast austenitic stainless steel in treated water—borated less than 140 °F is identified as being subject to loss of material. No aging effects are identified for stainless steel components in air and gas, indoor not-air-conditioned, concrete, and containment environments. No aging effects are identified for stainless steel fasteners (bolting) in borated water leaks from other plant systems. No aging effects are identified for CASS components in air and gas, containment, and indoor not-air-conditioned environments.

Carbon/low-alloy steel components in treated water—other are identified as being subject to loss of material. Carbon/low-alloy steel components in borated water leaks are identified as being subject to loss of material. Carbon/low-alloy steel fasteners (bolting) in an indoor not-air-conditioned environment are identified as being subject to loss of material and loss of preload due to stress relaxation. Since there are no bolts with a specified minimum yield strength greater than 150 ksi in the ESF systems, SCC is not an applicable aging effect/mechanism.

Cast iron components are identified as being subject to loss of material in treated water—other and indoor not-air-conditioned environments.

Aging Management Programs

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

- Bolting Integrity Program
- Water Chemistry Control Program
- Boric Acid Corrosion Prevention Program
- One-Time Inspection Program
- Systems Monitoring Program
- Closed-Cycle (Component) Cooling Water System Program

A description of these AMPs is provided in Appendix B of the LRA.

3.2.2.4.3.2 Staff Evaluation

Aging Effects

The staff reviewed the information in LRA Tables 2.3.2-3, 3.3-1, and 3.3-2 for the RHR system. During its review, the staff determined that additional information was needed to complete its review.

In RAI 3.3-3x2, the staff requested the applicant to provide its basis of determining in LRA Table 3.3-2, line 11, that there are no aging effects requiring management for the stainless steel fasteners (bolting) in the borated water leakages environments. The staff's discussion of this RAI and its resolution by the applicant are provided in Section 3.2.2.4.1.2 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 RHR system SCs to the environments described in LRA Tables 2.3.2-3, 3.3-1 and 3.3-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the RHR system.

Aging Management Programs

The applicant credited the following AMPs with managing the aging effects in the RHR system:

- Water Chemistry Control Program (3.0.3.1)
- Bolting Integrity Program (3.0.3.3)
- Boric Acid Corrosion Prevention Program (3.0.3.4)
- Closed-Cycle (Component) Cooling Water System Program (3.0.3.5)
- One-Time Inspection Program (3.0.3.7)
- Systems Monitoring Program (3.0.3.11)

These AMPs are credited with managing the aging effects of several components in other structures and systems and, therefore, are 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 the SER sections given in parentheses above.

After evaluating the applicant's AMR for each of the components in the RHR system, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects. For those components identified in Table 3.3-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in LRA Table 3.3-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effects.

Based on its review of the information provided in the LRA, the staff concludes that the above identified AMPs will effectively manage the aging effects for the components of the RHR system.

3.2.2.4.3.3 Conclusions. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and the AMPs credited with managing the aging effects for the RHR system, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

3.2.2.4.4 Containment Hydrogen Detectors and Recombiner System

3.2.2.4.4.1 Summary of Technical Information in the Application. The description of the containment hydrogen detectors and recombiner (CHDR) system can be found in Section

2.3.2.4 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3.2-4. The components, aging effects, and AMPs are provided in LRA Tables 3.3-1 and 3.3-2.

Aging Effects

Components of the CHDR system are described in LRA Section 2.3.2.4 as being within the scope of license renewal and subject to an AMR. Table 2.3.2-4 of the LRA lists individual components of the system including blower casing, controller, carbon steel components, fasteners (bolting), filter housing, flow element, pipe, pump casing, recombiner casing, valve body, and ventilation ductwork.

Carbon/low-alloy steel components are identified as being subject to loss of material in air and gas (wetted) less than 140 °F, borated water leakages, indoor not-air-conditioned, buried, and containment environments. Carbon/low-alloy steel fasteners (bolting) in an indoor not-air-conditioned environment are identified as being subject to loss of material and loss of preload due to stress relaxation. No aging effects are identified for carbon/low-alloy steel components in air and gas environments. Since there are no bolts with a specified minimum yield strength greater than 150 ksi in the ESF systems, SCC is not an applicable aging effect/mechanism.

No aging effects are identified for galvanized carbon steel in air and gas (wetted) less than 140 °F, and containment environments. No aging effects are identified for copper alloy (zinc less than 15 percent) in air and gas, containment, and indoor not-air-conditioned environments.

No aging effects are identified for stainless steel components in air and gas, air and gas (wetted) less than 140 °F, borated water leaks, containment, and outdoor environments. No aging effects are identified for CASS components in air and gas and indoor not-air-conditioned environments.

Cast iron components in indoor not-air-conditioned environments are identified as being subject to loss of material. No aging effects are identified for cast iron in air and gas environments.

Aging Management Programs

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

- Bolting Integrity Program
- Boric Acid Corrosion Prevention Program
- Periodic Surveillance and Preventive Maintenance Program
- One-Time Inspection Program
- Systems Monitoring Program

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

3.2.2.4.4.2 Staff Evaluation

Aging Effects

The staff reviewed the information in LRA Tables 2.3.2-4, 3.3-1, and 3.3-2 for the CHDR system. During its review, the staff determined that additional information was needed to complete its review.

In RAI 3.3-3x2, the staff requested the applicant to provide its basis for determining in LRA Table 3.3-2, line 11, that there are no aging effects requiring management for the stainless steel fasteners (bolting) in the borated water leakages environments. The staff's discussion of this RAI and its resolution by the applicant are provided in Section 3.2.2.4.1.2 of this SER.

In LRA Table 3.3-2, rows 44, 45, 67, 88, and 89, for copper alloy (zinc less than 15 percent) pipe, thermowell, and valve body exposed to containment or indoor not-air-conditioned environments, the applicant identified no aging effects requiring management. In RAI 3.3-4, the staff requested the applicant to provide the basis for this determination. By letter dated May 23, 2003, the applicant stated that copper and copper alloy materials (brass and bronzes) with zinc less than 15 percent display excellent resistance to atmospheric corrosion in a variety of environments, including industrial, marine, and rural atmospheres. The applicant stated that the American Society for Metals (ASM) Metal Handbook, Volume 13, "Corrosion," states that "Comprehensive tests conducted over a 20-year period under the supervision of ASTM, as well as many service records, have confirmed the suitability of copper and copper alloys for atmospheric exposure." Corrosion rate data published in Volume 13 of the ASM Metal Handbook indicates that corrosion rates range from 0.002 mils/yr in rural environments to approximately 0.1 mils/yr in industrial/marine environments. These rates are essentially negligible. The applicant also stated that plant-specific operating experience at Ginna has revealed no evidence of corrosion-related degradation of copper alloy components exposed to indoor not-air-conditioned and containment environments. On the basis of this specific technical data and the plant-specific operating experience, the staff finds the applicant's response to this issue to be acceptable.

In LRA Table 3.3-2, lines 97 and 98, for galvanized carbon steel ventilation ductwork, exposed to air and gas (wetted) less than 140 °F, or containment environments, the applicant identified no aging effects requiring management. In RAI 3.3.5, the staff requested the applicant to provide the basis for this determination. By letter dated May 23, 2003, the applicant stated that the internal and external environments in the containment ventilation ductwork are essentially equal in temperature and, therefore, condensation necessary to support corrosion on galvanized steel would not be expected to occur on ductwork surfaces. The galvanized coating on carbon steel substrate is intended to behave as a sacrificial layer, thereby protecting the carbon steel. Based on the above plant-specific review and the standard industry guidance which indicates that galvanized carbon steel exposed to ventilation air (T less than140 °F) would be expected to exhibit minimal deterioration of the zinc coating, the staff finds the applicant's response to be acceptable.

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 CHDR system SCs with the environments described in LRA Tables 2.3.2-4, 3.3-1, and 3.3-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the CHDR system.

Aging Management Programs

The applicant credited the following AMPs with managing the aging effects in the CHDR system:

- Bolting Integrity Program (3.0.3.3)
- Boric Acid Corrosion Prevention Program (3.0.3.4)
- One-Time Inspection Program (3.0.3.7)
- Periodic Surveillance and Preventive Maintenance Program (3.0.3.8)
- Systems Monitoring Program (3.0.3.11)

These AMPs are credited with managing the aging effects of several components in other structures and systems and, therefore, are 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 the SER sections given in parentheses above.

After evaluating the applicant's AMR for each of the components in the CHDR system, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects. For those components identified in Table 3.3-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in LRA Table 3.3-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effects.

In LRA Table 3.3-2, line 42, the One-Time Inspection Program is utilized to manage loss of material for the carbon/low-alloy steel pipe in a buried environment. In RAI 3.3-2, the staff requested the applicant to provide the basis for its assertion that, for the above material/environment combination, the One-Time Inspection Program alone is adequate to ensure that the aging effect will be effectively managed during the extended period of operation. By letter dated May 23, 2003, the applicant stated that the aging management activities associated with this buried pipe include removing the surrounding fill and performing a one-time inspection to verify that the pipe has not been degraded by corrosion. The applicant stated that omitted from the application was information that the pipe will subsequently be included in the plant-specific Systems Monitoring Program. Hence, one-time inspections alone will not be used for this material/environment combination. On the basis that the One-Time Inspection Program will be supplemented by the Systems Monitoring Program, the staff finds the applicant's response to be acceptable for the buried pipe.

Based on its review of the information provided in the LRA, the staff concludes that the above identified AMPs will effectively manage the aging effects for the components of the CHDR system.

3.2.2.4.4.3 Conclusions. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and the AMPs credited with managing the aging effects for the CHDR system, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

3.2.2.4.5 Containment Isolation Components System

3.2.2.4.5.1 Summary of Technical Information in the Application. The description of the containment isolation component (CIC) system can be found in Section 2.3.2.5 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3.2-5. The components, aging effects, and AMPs are provided in LRA Tables 3.3-1 and 3.3-2.

Aging Effects

Components of the CIC system are described in LRA Section 2.3.2.5 as being within the scope of license renewal and subject to an AMR. Table 2.3.2-5 of the LRA lists individual components of the system including carbon steel components, delay coil, fasteners (bolting), flange, pipe, thermowell, and valve body.

Stainless steel components in treated water primary, 140<T<480, are identified as being subject to loss of material and cracking due to SCC. Cast austenitic stainless steel in raw water drainage is identified as being subject to loss of material. No aging effects are identified for stainless steel components in air and gas (wetted) less than 140 °F, containment, borated water leaks, and indoor not-air-conditioned environments. No aging effects are identified for cast austenitic stainless steel components in air and gas (wetted) less than 140 °F, containment, and indoor not-air-conditioned environments.

Carbon/low-alloy steel components are identified as being subject to loss of material in borated water leaks environments. Carbon/low-alloy steel fasteners (bolting) in indoor not-air-conditioned environments are identified as being subject to loss of material and loss of preload due to stress relaxation. Carbon/low-alloy steel is identified as being subject to loss of material when exposed to containment, outdoor, indoor not-air-conditioned, and air and gas (wetted) less than 140 °F environments. No aging effects are identified for carbon/low-alloy steel in air and gas environments. Since there are no bolts with a specified minimum yield strength greater than 150 ksi in the ESF systems, SCC is not an applicable aging effect/mechanism.

Copper alloy (zinc less than 15 percent) components in air and gas (wetted) less than 140 °F are identified as being subject to loss of material. No aging effects are identified for copper alloy (zinc less than 15 percent) in air and gas, containment, and indoor not-air-conditioned environments.

Aging Management Programs

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

- Bolting Integrity Program
- Water Chemistry Control Program
- Boric Acid Corrosion Prevention Program
- Periodic Surveillance and Preventive Maintenance Program
- One-Time Inspection Program
- System Monitoring Program

A description of these AMPs is provided in Appendix B of the LRA.

3.2.2.4.5.2 Staff Evaluation

Aging Effects

The staff reviewed the information in LRA Tables 2.3.2-5, 3.3-1, and 3.3-2 for the CIC system. During its review, the staff determined that additional information was needed to complete its review.

In RAI 3.3-4, the staff requested the applicant to provide its basis for determining in LRA Table 3.3-2, lines 44, 45, 67, 88, and 89, that there are no aging effects requiring management for copper alloy (zinc less than 15 percent) pipe, thermowell, and valve body exposed to containment or indoor not-air-conditioned environments. The staff's discussion of this RAI and its resolution by the applicant are provided in Section 3.2.2.4.4.2 of this SER.

In RAI 3.3-3x2, the staff requested the applicant to provide its basis for determining in LRA Table 3.3-2, line 11, that there are no aging effects requiring management for the stainless steel fasteners (bolting) in the borated water leakages environments. The staff's discussion of this RAI and its resolution by the applicant are provided in Section 3.2.2.4.1.2 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 responses to the above RAIs, the staff finds that the aging effects that result from contact of the CIC system SCs with the environments described in LRA Tables 2.3.2-5, 3.3-1, and 3.3-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the CIC system.

Aging Management Programs

The applicant credited the following AMPs with managing the aging effects in the CIC system:

- Water Chemistry Control Program (3.0.3.1)
- Bolting Integrity Program (3.0.3.3)
- Boric Acid Corrosion Prevention Program (3.0.3.4)

- One-Time Inspection Program (3.0.3.7)
- Periodic Surveillance and Preventive Maintenance Program (3.0.3.8)
- Systems Monitoring Program (3.0.3.11)

These AMPs are credited with managing the aging effects of several components in other structures and systems and, therefore, are 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 the SER sections given in parentheses above. After evaluating the applicant's AMR for each of the components in the CIC system, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects. For those components identified in Table 3.3-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in LRA Table 3.3-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effects.

In LRA Table 3.3-2, lines 41 and 66, the One-Time Inspection Program is utilized to manage loss of material for the carbon/low-alloy steel pipe and copper alloy (zinc less than 15 percent) thermowell, respectively, in air and gas (wetted) less than 140 °F environments. In RAI 3.3-2, the staff requested the applicant to provide the basis for its assertion that, for the above material/environment combination, the One-Time Inspection Program alone is adequate to ensure that the aging effect will be effectively managed during the extended period of operation. By letter dated May 23, 2003, the applicant stated that for the carbon/low-alloy steel pipe included in line 41, a review of Ginna specific operating experience for this material/environment grouping shows no instances of age-related degradation. This specific piping is associated with the heating steam system carbon steel piping to and from containment. This piping has been cut off and a pipe cap installed by welding at each end. The applicant stated that a one-time inspection of the piping segments at penetrations 301 and 303, which have been out of service for more than 10 years, will be performed prior to the period of extended operation. This inspection will be performed on the exterior surfaces of the segments utilizing ultrasonic methods and will include inspection locations along the bottom and sides of the pipe(s) on the containment and intermediate building sides. In addition, the applicant stated that appropriate corrective action will be taken as necessary. Based on the configuration of the piping segments, the proposed methods of inspection and locations, as well as the provisions of the corrective action, the staff finds the One-Time Inspection Program to be acceptable for managing the identified aging effect.

For the copper alloy (zinc less than 15 percent) thermowell in an air and gas (wetted) less than 140 °F environment (line number (66)), the applicant stated that a review of Ginna specific operating experience reveals no occurrences of age-related degradation for this material/environment grouping. The applicant stated that a one-time inspection of components in this material/environment grouping is appropriate to verify the improbability of age-related degradation. Based on the Ginna specific operating experience and the applicant's response to RAI 3.3-4 regarding the corrosion resistance of copper alloys (zinc less than 15 percent), the staff finds the applicant's use of the One-Time Inspection Program to be acceptable.

Based on its review of the information provided in the LRA, the staff concludes that the above identified AMPs will effectively manage the aging effects for the components of the CIC system.

3.2.2.4.5.3 Conclusions. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and the AMPs credited with managing the aging effects for the CIC system, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

3.2.3 Evaluation Findings

The staff has reviewed the information in Section 3.3 of the LRA. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and the AMPs credited with managing the aging effects for the ESF system, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB during the period of extended operation. The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement provides an adequate program description of the AMPs credited with managing aging effects, as required by 10 CFR 54.21(d).

3.3 Auxiliary Systems

This section addresses the aging management of the components of the auxiliary systems group. The systems that make up the auxiliary systems group are described in the following SER sections noted below:

- Chemical and Volume Control (2.3.3.1)
- Component Cooling Water (2.3.3.2)
- Spent Fuel Pool Cooling and Fuel Storage (2.3.3.3)
- Waste Disposal (2.3.3.4)
- Service Water (2.3.3.5)
- Fire Protection (2.3.3.6)
- Heating (2.3.3.7)
- Emergency Power (2.3.3.8)
- Containment Ventilation (2.3.3.9)
- Essential Ventilation (2.3.3.10)
- Cranes, Hoists, and Lifting Devices (2.3.3.11)
- Treated Water (2.3.3.12)
- Radiation Monitoring (2.3.3.13)
- Circulating Water (2.3.3.14)
- Chilled Water (2.3.3.15)
- Fuel Handling (2.3.3.16)
- Plant Sampling (2.3.3.17)
- Plant Air (2.3.3.18)
- Nonessential Ventilation (2.3.3.19)
- Site Service and Facility Support (2.3.3.20)

As discussed in Section 3.0.1 of this SER, the components in each of these auxiliary systems are included in one of two LRA tables. Table 3.4-1 of the LRA consists of auxiliary system components that are evaluated in the GALL Report, and LRA Table 3.4-2 consists of auxiliary system components that are not evaluated in the GALL Report.

3.3.1 Summary of Technical Information in the Application

In LRA Section 3.4, the applicant described its AMRs for the auxiliary systems group at Ginna. The description of the systems that comprise the auxiliary systems group can be found in LRA Section 2.3.3. The passive, long-lived components in these systems that are subject to an AMR are identified in LRA Tables 2.3.3-1 through 2.3.3-20.

The applicant's AMRs included an evaluation of plant-specific and industry operating experience. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify aging effects that require management. These reviews concluded that the aging effects requiring management based on Ginna's operating experience were consistent with aging effects identified in GALL.

The applicant's review of industry operating experience included a review of operating experience through 2002. The results of this review concluded that aging effects requiring management based on industry operating experience were consistent with aging effects identified in GALL.

The applicant's ongoing review of plant-specific and industry-wide operating experience is conducted in accordance with the Ginna Operating Experience Program.

3.3.2 Staff Evaluation

In Section 3.4 of the LRA, the applicant describes its AMR for the auxiliary systems at Ginna. The staff reviewed LRA Section 3.4 to determine whether the applicant has provided sufficient information to demonstrate that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the period of extended operation, in accordance with the requirements of 10 CFR 54.21(a)(3), for the auxiliary system components that are determined to be within the scope of license renewal and subject to an AMR.

The applicant referenced the GALL Report in its AMR. The staff has previously evaluated the adequacy of the aging management of auxiliary system components for license renewal as documented in the GALL Report. Thus, the staff did not repeat its review of the matters described in the GALL Report, except to ensure that the material presented in the LRA was applicable and to verify that the applicant had identified the appropriate programs as described and evaluated in the GALL Report. The staff evaluated those aging management issues recommended for further evaluation in the GALL Report. The staff also reviewed aging management information submitted by the applicant that was different from that in the GALL Report or was not addressed in the GALL Report. Finally, the staff reviewed the UFSAR

Supplement to ensure that it provided an adequate description of the programs credited with managing aging for the auxiliary system components.

Table 3.3-1 below provides a summary of the staff's evaluation of components, aging effects/mechanisms, and AMPs listed in LRA Section 3.4 that are addressed in the GALL Report.

Table 3.3-1 Staff Evaluation Table for Ginna Auxiliary System Components Evaluated in the GALL Report

Component Group	Aging Effect/Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Components in spent fuel pool cooling and cleanup	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Water Chemistry Control Program, Periodic Surveillance and Preventive Maintenance Program, One-Time Inspection Program	GALL recommends further evaluation (see Section 3.3.2.2.1 below)
Linings in spent fuel pool cooling and cleanup system; seals and collars in ventilation systems	Hardening, cracking, and loss of strength due to elastomer degradation; loss of material due to wear	Plant specific	One-Time Inspection Program, Periodic Surveillance and Preventive Maintenance Program, Systems Monitoring Program	Consistent with GALL. GALL recommends further evaluation (see Section 3.3.2.2.2 below)
Components in load handling, chemical and volume control system (PWR); reactor water cleanup and shutdown cooling systems (older BWR)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	TLAA	GALL recommends further evaluation (see Section 3.3.2.2.3 below)
Heat exchangers in reactor water cleanup system (BWR); high-pressure pumps in chemical and volume control system (PWR)	Crack initiation and growth to SCC or cracking	Plant specific	Water Chemistry Control Program, One-Time Inspection Program, Periodic Surveillance and Preventive Maintenance Program	Consistent with GALL. GALL recommends further evaluation (see Section 3.3.2.2.4 below)

Component Group	Aging Effect/Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Components in ventilation systems, diesel fuel oil system, and emergency diesel generator systems; external surfaces of carbon steel components	Loss of material due to general, pitting, and crevice corrosion, and MIC	Plant specific	One-Time Inspection Program, Periodic Surveillance and Preventive Maintenance Program, Closed-Cycle (Component) Cooling Water System Program, Fuel Oil Chemistry Program, Systems Monitoring Program	Consistent with GALL. GALL recommends further evaluation (see Section 3.3.2.2.5 below)
Components in reactor coolant pump oil collection system of fire protection system	Loss of material due to galvanic, general, pitting, and crevice corrosion	One-Time Inspection	Fire Protection Program	Consistent with GALL (see Section 3.3.2.3.2 below)
Diesel fuel oil tanks in diesel fuel oil system and emergency diesel generator system	Loss of material due to general, pitting, and crevice corrosion, MIC, and biofouling	Fuel Oil Chemistry and One-Time Inspection	Fuel Oil Chemistry Program, Periodic Surveillance and Preventive Maintenance Program	Consistent with GALL. GALL recommends further evaluation (see Section 3.3.2.2.7 below)
Piping, pump casing, and valve body and bonnets in shutdown cooling system (older BWR)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Not applicable	BWR
Heat exchangers in chemical and volume control system	Crack initiation and growth to SCC and cyclic loading	Water Chemistry and a Plant-Specific Verification Program	Water Chemistry Control Program, One-Time Inspection Program, Periodic Surveillance and Preventive Maintenance Program	Consistent with GALL. GALL recommends further evaluation (see Section 3.3.2.2.8 below)
Neutron-absorbing sheets in spent fuel storage racks	Reduction of neutron-absorbing capacity and loss of material due to general corrosion (boral, boron steel)	Plant specific	Periodic Surveillance and Preventive Maintenance Program, Spent Fuel Pool Neutron Absorber (Borated Stainless Steel) Monitoring Program	Consistent with GALL. GALL recommends further evaluation (see Section 3.3.2.2.9 below)
New fuel rack assembly	Loss of material due to general, pitting, and crevice corrosion	Structures Monitoring	Systems Monitoring Program	Consistent with GALL (see Section 3.3.2.1 below)

Component Group	**Aging Effect/Mechanism**	**AMP in GALL Report**	**AMP in LRA**	**Staff Evaluation**
Spent fuel storage racks and valves in spent fuel pool cooling and cleanup	Crack initiation and growth due to stress-corrosion cracking	Water Chemistry	Water Chemistry Control Program, One-Time Inspection Program, Periodic Surveillance and Preventive Maintenance Program	Consistent with GALL (see Section 3.3.2.1 below)
Neutron-absorbing sheets in spent fuel storage racks	Reduction of neutron-absorbing capacity due to Boraflex degradation	Boraflex Monitoring	Not applicable	Ginna uses borated stainless steel sheets instead of Boraflex sheets.
Closure bolting and external surfaces of carbon steel and low-alloy steel components	Loss of material due to boric acid	Boric Acid Corrosion	Boric Acid Corrosion Program	Consistent with GALL (see Section 3.3.2.1 below)
Components in or serviced by closed-cycle cooling water system	Loss of material due to general and pitting corrosion and MIC	Closed-Cycle Cooling Water System	Closed-Cycle (Component) Cooling Water System Program	Consistent with GALL (see Section 3.3.2.1 below)
Cranes including bridge and trolleys and rail system in load handling systems	Loss of material due to general corrosion and wear	Overhead Heavy Load and Light Load Handling Systems	Periodic Surveillance and Preventive Maintenance Program, and Heavy and Light Load (Related to Refueling) Handling Systems Program	Consistent with GALL (see Section 3.3.2.1 below)
Components in or serviced by open-cycle cooling water systems	Loss of material due to general, pitting, crevice, and galvanic corrosion, MIC, and biofouling; buildup of deposit due to biofouling	Open-Cycle Cooling Water System	Open-Cycle Cooling (Service) Water System Program and Periodic Surveillance and Preventive Maintenance Program	Consistent with GALL (see Section 3.3.2.1 below)
Buried piping and fittings	Loss of material due to general, pitting, and crevice corrosion and MIC	Buried Piping and Tanks Surveillance or Buried Piping and Tanks Inspection	Buried Piping and Tanks Inspection Program, Periodic Surveillance and Preventive Maintenance Program, One-Time Inspection Program, and Fire Water System Program	Consistent with GALL (see Section 3.3.2.1 below) GALL recommends further evaluation (see Sections 3.3.2.3.2 and 3.3.2.2.10 below)

Component Group	Aging Effect/Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Components in compressed air system	Loss of material due to general and pitting corrosion	Compressed Air Monitoring	Not applicable	Components are not in the scope of LRA.
Components (doors and barrier penetration seals) and concrete structures in fire protection	Loss of material due to wear; hardening and shrinkage due to weathering	Fire Protection	Fire Protection Program	Consistent with GALL (see Section 3.3.2.3.2 below)
Components in water-based fire protection	Loss of material due to general, pitting, crevice, and galvanic corrosion, MIC, and biofouling	Fire Water System	Fire Water System Program and Periodic Surveillance and Preventive Maintenance Program	Consistent with GALL (see Sections 3.3.2.3.2 and 3.0.3.8).
Components in diesel fire system	Loss of material due to galvanic, general, pitting, and crevice corrosion	Fire Protection and Fuel Oil Chemistry	Fuel Oil Chemistry Program, and Periodic Surveillance and Preventive Maintenance Program	Consistent with GALL (see Section 3.3.2.3.2 below)
Tanks in diesel fuel oil system	Loss of material due to general, pitting, and crevice corrosion	Aboveground Carbon Steel Tanks	Not applicable	There are no aboveground tanks in Ginna's diesel fuel oil system.
Closure bolting	Loss of material due to general corrosion; crack initiation and growth due to cyclic loading and SCC	Bolting Integrity	Bolting Integrity Program	Consistent with GALL (see Section 3.3.2.1 below)
Components in reactor water cleanup system	Crack initiation and growth due to SCC and IGSCC	Reactor Water Cleanup System Inspection	Not applicable	BWR
Components in shutdown cooling system (older BWR)	Crack initiation and growth due to SCC	BWR Stress Corrosion Cracking and Water Chemistry	Not applicable	BWR
Components in shutdown cooling system (older BWR)	Loss of material due to pitting and crevice corrosion and MIC	Closed-Cycle Cooling Water System	Not applicable	BWR

Component Group	Aging Effect/Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Components (aluminum bronze, brass, cast iron, cast steel) in open-cycle and closed-cycle cooling water systems, and ultimate heat sink	Loss of material due to selective leaching	Selective Leaching of Materials	Open-Cycle Cooling (Service) Water System Program, Closed-Cycle (Component) Cooling Water System Program, and Periodic Surveillance and Preventive Maintenance Program or One-Time Inspection Program	Consistent with GALL (see Section 3.3.2.1 below)
Fire barriers, walls, ceilings and floors in fire protection	Concrete cracking and spalling due to freeze-thaw, aggressive chemical attack, and reaction with aggregates; loss of material due to corrosion of embedded steel	Fire Protection and Structures Monitoring	Fire Protection Program and Structures Monitoring Program	Consistent with GALL (see Section 3.3.2.3.2 below)

The staff's review of the auxiliary systems for the Ginna LRA is contained within four sections of this SER. Section 3.3.2.1 is the staff review of components in the auxiliary systems that the applicant indicates are consistent with GALL and do not require further evaluation. Section 3.3.2.2 is the staff review of components in the auxiliary systems that the applicant indicates are consistent with GALL and for which GALL recommends further evaluation. Section 3.3.2.3 is the staff evaluation of AMPs that are specific to the auxiliary systems group. Section 3.3.2.4 contains an evaluation of the adequacy of aging management for components in each system in the auxiliary systems group and includes an evaluation of components in the auxiliary systems that the applicant indicates are not in GALL.

3.3.2.1 Aging Management Evaluations in the GALL Report That Are Relied on for License Renewal, Which Do Not Require Further Evaluation

For component groups evaluated in GALL for which the applicant has claimed consistency with GALL, and for which GALL does not recommend further evaluation, the staff sampled components in these groups to determine whether the plant-specific components contained in these GALL component groups were bounded by the GALL evaluation. The staff also sampled component groups to determine whether the applicant had properly identified those component groups in GALL that were not applicable to its plant. The staff identified several areas where additional information or clarification was needed. The staff's evaluation of the applicant's responses to those RAIs is included in Section 3.3.2.4 of this SER.

On the basis of its review, the staff has verified the applicant's claim of consistency with the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 50.21(a)(3).

3.3.2.2 Aging Management Evaluations in the GALL Report That Are Relied on for License Renewal, for Which GALL Recommends Further Evaluation

For component groups evaluated in the GALL Report for which the applicant has claimed consistency with GALL and for which the GALL Report recommends further evaluation, the staff reviewed the applicant's evaluation to determine whether it adequately addressed the issues for which GALL recommended further evaluation. In addition, the staff sampled components in these groups to determine whether the plant-specific components contained in these GALL component groups were bounded by the GALL evaluation.

The GALL Report indicates that further evaluation should be performed in the areas described in the following sections.

3.3.2.2.1 Loss of Material Due to General, Pitting, and Crevice Corrosion

Loss of material due to general, pitting, and crevice corrosion could occur in the channel head and access cover, tubes, and tubesheets of the heat exchanger in the spent fuel pool cooling and cleanup system, while loss of material due to pitting and crevice corrosion could occur in the filter housing, valve bodies, and nozzles of the ion exchanger in the spent fuel pool cooling and cleanup system. The Water Chemistry Control Program relies on monitoring and control of reactor water chemistry based on EPRI guidelines TR-105714 for primary water chemistry in PWRs, and TR-102134 for secondary water chemistry in PWRs, to manage the effects of loss of material from general, pitting, or crevice corrosion. However, high concentrations of impurities at crevices and locations of stagnant flow conditions could cause general, pitting, or crevice corrosion. Therefore, verification of the effectiveness of the Water Chemistry Control Program should be performed to ensure that corrosion is not occurring. The GALL Report recommends further evaluation of programs to manage loss of material from general, pitting, and crevice corrosion to verify the effectiveness of the Water Chemistry Control Program. A one-time inspection of select components at susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

The staff reviewed the applicant's proposed program to ensure that corrosion is not occurring and that the components' intended functions will be maintained during the period of extended operation. If the applicant proposed a one-time inspection of select components at susceptible locations to ensure that corrosion is not occurring, the staff verified that the applicant's selection of susceptible locations is based on severity of conditions, time of service, and lowest design margin. The staff also verified that the proposed inspection would be performed using techniques similar to ASME Code and ASTM standards, including visual, ultrasonic, and surface techniques.

The applicant credited the Water Chemistry Control Program with managing the aging effects of loss of material due to general, pitting, and crevice corrosion for the applicable spent fuel cooling and fuel storage system components. In addition, the One-Time Inspection Program, as well as the Periodic Surveillance and Preventive Maintenance Program, will be used to verify the effectiveness of the Water Chemistry Control Program. The staff evaluation of these AMPs is discussed in Sections 3.0.3.1, 3.0.3.7, and 3.0.3.8 of this SER, respectively. The staff finds that these AMPs can effectively manage the general, pitting, and crevice corrosion for the above components that are applicable to the Ginna spent fuel cooling and fuel storage (SFC&FS) system.

On the basis of its review, the staff finds that the applicant appropriately evaluated AMR results involving management of loss of material due to general, pitting, and crevice corrosion for applicable components in the SFC&FS system, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with the GALL Report, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.2 Hardening and Cracking or Loss of Strength Due to Elastomer Degradation, or Loss of Material Due to Wear

The GALL Report recommends further evaluation of programs to manage the hardening and cracking due to elastomer degradation of valves in the spent fuel pool cooling and cleanup system. The GALL Report also recommends further evaluation of programs to manage the hardening and loss of strength due to elastomer degradation of the collars and seals of the duct, and of the elastomer seals of the filters in the control room area, auxiliary and radwaste area, and primary containment heating and ventilation systems, and of the collars and seals of the duct in the diesel generator building ventilation system. The GALL Report also recommends further evaluation of programs to manage the loss of material due to wear of the collars and seals of the ducts in the ventilation systems. The staff reviewed the applicant’s proposed programs to ensure that an adequate program will be in place for the management of these aging effects.

The applicant stated that the spent fuel cooling system at Ginna contains no components that are elastomer lined. The applicant also stated that the One-Time Inspection and Periodic Surveillance and Preventive Maintenance Programs are credited with managing the aging effects of hardening, cracking, and loss of strength for the applicable ventilation systems components. In addition, the Systems Monitoring Program is credited with managing the aging effect of loss of material due to wear for these components. The staff evaluation of these AMPs is discussed in Sections 3.0.3.7, 3.0.3.8, and 3.0.3.11 of this SER, respectively. The staff finds that these AMPs can effectively manage the elastomer degradation of the above components that are applicable to Ginna auxiliary systems.

On the basis of its review, the staff finds that the applicant appropriately evaluated AMR results involving management of hardening and cracking or loss of strength due to elastomer degradation or loss of material due to wear for components in the applicable auxiliary systems, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with the GALL Report, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.3 Cumulative Fatigue Damage

Fatigue is a TLAA as defined in 10 CFR 54.3. All TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The staff's evaluation of this TLAA is documented in Section 4.3 of this SER, following the guidance in Section 4.3 of the SRP-LR.

3.3.2.2.4 Crack Initiation and Growth Due to Cracking or Stress-Corrosion Cracking

The GALL Report recommends further evaluation of programs to manage crack initiation and growth due to cracking of the high-pressure pump in the chemical and volume control system. The staff reviewed the applicant's proposed program to ensure that an adequate program will be in place for the management of this aging effect.

The applicant credited the Water Chemistry Control Program for managing the crack initiation and growth due to SCC in the high-pressure pump in the chemical and volume control system. The applicant stated that the Water Chemistry Control Program is consistent with the GALL Report and will preclude the possibility of crack initiation and growth due to SCC of the high-pressure pump in the chemical and volume control system. The applicant also stated that the One-Time Inspection Program, as well as the Periodic Surveillance and Preventive Maintenance Program, is credited with verifying the adequacy of the Water Chemistry Control Program. The staff evaluation of these AMPs is discussed in Sections 3.0.3.1, 3.0.3.7, and 3.0.3.8 of this SER, respectively. The One-Time Inspection Program and the Periodic Surveillance and Preventive Maintenance Program will be capable of detecting cracking; therefore, the staff finds the proposed inspections to be acceptable for managing the potential for cracking of the high-pressure pump in the chemical and volume control system.

On the basis of its review, the staff finds that the applicant appropriately evaluated AMR results involving management of crack initiation and growth due to cracking or SCC for components in the applicable auxiliary systems, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with the GALL Report, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.5 Loss of Material Due to General, Microbiologically Influenced, Pitting, and Crevice Corrosion

The GALL Report recommends further evaluation of programs to manage the loss of material due to general, pitting, and crevice corrosion of the piping, filter housing, and supports in the control room area, the auxiliary and radwaste area, and the primary containment heating and ventilation systems; of the piping of the diesel generator building ventilation system; of the aboveground piping and fittings, valves, and pumps in the diesel fuel oil system; and of the diesel engine starting air, combustion air intake, and combustion air exhaust subsystems in the EDG system. The GALL Report also recommends further evaluation of programs to manage the loss of material due to general, pitting, and crevice corrosion, and MIC of the duct fittings, access doors, closure bolts, equipment frames, and housing of the duct, due to pitting and crevice corrosion of the heating/cooling coils of the air handler heating/cooling, and due to general corrosion of the external surfaces of all carbon steel structures and components, including bolting exposed to operating temperatures less than 212 ºF in the ventilation systems. The staff reviewed the applicant’s proposed program to ensure that an adequate program will be in place for the management of these aging effects.

The applicant credited the One-Time Inspection, Periodic Surveillance and Preventive Maintenance, Closed-Cycle (Component) Cooling Water System, and the Fuel Oil Chemistry Programs with managing the identified aging effects of the applicable components in the ventilation systems, the diesel fuel oil systems, and the EDG system. In addition, the applicant credited the Systems Monitoring Program with managing the aging effects of loss of material for the external surfaces of all carbon steel components. The staff evaluation of these AMPs is documented in Sections 3.0.3.7, 3.0.3.8, 3.0.3.5, 3.3.2.3.4, and 3.0.3.11 of this SER, respectively. The staff finds that these AMPs can effectively manage the corrosion of internal and external surfaces for the above components that are applicable to Ginna auxiliary systems.

On the basis of its review, the staff finds that the applicant appropriately evaluated AMR results involving management of the loss of material due to general, MIC, pitting, and crevice corrosion for components in the applicable auxiliary systems, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with the GALL Report, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.6 Loss of Material Due to General, Galvanic, Pitting, and Crevice Corrosion

The GALL Report recommends further evaluation of programs to manage the loss of material due to general, galvanic, pitting, and crevice corrosion of tanks, piping, valve bodies, and tubing in the RCP oil collection system in the fire protection system. The Fire Protection Program relies on a combination of visual and volumetric examinations in accordance with the guidelines of Appendix R to 10 CFR Part 50 and Branch Technical Position 9.5-1 to manage loss of material from corrosion. However, corrosion may occur at locations not routinely examined. Therefore, verification of the effectiveness of the program should be performed to ensure that degradation is not occurring and that the components’ intended function will be maintained during the period of extended operation. The staff reviewed the applicant’s proposed program to ensure that corrosion is not occurring and that the components’ intended function will be maintained during the period of extended operation. The applicant has proposed a one-time visual inspection of the RCP oil collection system. A favorable result for this inspection will ensure that corrosion is not occurring. If corrosion is identified, additional examinations would then be conducted on any problematic areas. The results of the examinations will be used as a leading indicator of other susceptible components. The proposed inspection would be performed using techniques similar to ASME Code and ASTM standards, including visual, ultrasonic, and surface examination techniques.

On the basis of its review, the staff finds that the applicant appropriately evaluated AMR results involving management of the loss of material due to general, galvanic, pitting, and crevice corrosion for components in the auxiliary systems, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with the GALL Report, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.7 Loss of Material Due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion, and Biofouling

The GALL Report recommends further evaluation of programs to manage loss of material due to general, pitting, and crevice corrosion, MIC, and biofouling of the internal surface of tanks in the diesel fuel oil system and due to general, pitting, crevice, and MIC of the tanks of the diesel engine fuel oil system in the EDG system. The Fuel Oil Chemistry Program relies on monitoring and control of fuel oil contamination in accordance with the guidelines of ASTM Standards D4057, D1796, D2709, and D2276 to manage loss of material due to corrosion or biofouling. Corrosion or biofouling may occur at locations where contaminants accumulate. Verification of the effectiveness of the Fuel Oil Program should be performed to ensure that corrosion/biofouling is not occurring and that the components’ intended function will be maintained during the period of extended operation.

The staff reviewed the applicant’s proposed program to ensure that corrosion/biofouling is not occurring and that the components’ intended function will be maintained during the period of extended operation. If an applicant proposes a one-time inspection of select components and susceptible locations to ensure that corrosion/biofouling is not occurring, the staff verified that the applicant’s selection of susceptible locations is based on severity of conditions, time of service, and lowest design margin. The staff also verified that the proposed inspection would be performed using techniques similar to ASME Code and ASTM standards, including visual, ultrasonic, and surface techniques.

The applicant credited the Fuel Oil Chemistry Program for managing the identified aging effects for the components in the applicable emergency power systems. In lieu of the One-Time Inspection Program, the applicant has chosen to use the Periodic Surveillance and Preventive Maintenance Program to verify the adequacy of the Fuel Oil Chemistry Program in managing these aging effects. The staff evaluation of these AMPs is documented in Sections 3.0.3.8 and 3.3.2.3.4 of this SER, respectively. The staff finds that these AMPs can effectively manage the aging effects for the above components that are applicable to Ginna auxiliary systems.

On the basis of its review, the staff finds that the applicant appropriately evaluated AMR results involving management of the loss of material due to general, pitting, crevice, and MIC, and biofouling for components in the applicable auxiliary systems, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with the GALL Report, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.8 Crack Initiation and Growth Due to Stress-Corrosion Cracking and Cyclic Loading

Crack initiation and growth due to SCC and cyclic loading could occur in the channel head and access cover, tubesheet, tubes, shell and access cover, and closure bolting of the regenerative heat exchanger, and in the channel head and access cover, tubesheet, and tubes of the letdown heat exchanger in the chemical and volume control system. The Water Chemistry Control Program relies on monitoring and control of water chemistry based on the guidelines of TR-105714 for primary water chemistry to manage the effects of crack initiation and growth due to SCC and cyclic loading. The GALL Report recommends further evaluation to manage crack initiation and growth from SCC and cyclic loading for this system to verify the effectiveness of the Water Chemistry Control Program. The staff reviewed the applicant's proposed program to ensure that cracking is not occurring and that the components' intended function will be maintained during the period of extended operation. A one-time inspection of select components and susceptible locations is an acceptable method to ensure that crack initiation and growth are not occurring and that the components' intended functions will be maintained during the period of extended operation. If the applicant proposed a one-time inspection of select components at susceptible locations to ensure that corrosion is not occurring, the staff verified that the applicant's selection of susceptible locations is based on severity of conditions, time of service, and lowest design margin. The staff also verified that the proposed inspection would be performed using techniques similar to ASME Code and ASTM standards, including visual, ultrasonic, and surface techniques.

The applicant credited the Water Chemistry Control Program for managing the aging effects of crack initiation and growth due to SCC of the heat exchanger in the chemical and volume control system. The applicant stated that the Water Chemistry Control Program is consistent with the GALL Report and will preclude the possibility of crack initiation and growth due to SCC of the high-pressure pump in the chemical and volume control system. The applicant also stated that the One-Time Inspection Program and the Periodic Surveillance and Preventive Maintenance Program are credited with verifying the adequacy of the Water Chemistry Control Program. The staff's evaluation of these AMPs is documented in Sections 3.0.3.1, 3.0.3.7, and 3.0.3.8 of this SER. The staff finds that these AMPs can effectively manage cracking of the applicable components in the chemical and volume control system.

On the basis of its review, the staff finds that the applicant appropriately evaluated AMR results involving management of crack initiation and growth due to SCC and cyclic loading for components in the applicable auxiliary systems, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with the GALL Report, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.9 Reduction of Neutron-Absorbing Capacity and Loss of Material Due to General Corrosion

Reduction of neutron-absorbing capacity and loss of material due to general corrosion could occur in the neutron-absorbing sheets of the spent fuel storage racks. The GALL Report recommends further evaluation of programs to manage these aging effects. The staff reviewed the applicant's proposed program to ensure that an adequate program will be in place for the management of these aging effects.

The applicant credited the Periodic Surveillance and Preventive Maintenance Program and the Spent Fuel Pool Neutron Absorber (borated stainless steel) Monitoring Program with managing the applicable aging effects of neutron-absorbing sheets in spent fuel storage racks. The staff evaluation of these AMPs is documented in Sections 3.0.3.8 and 3.3.2.3.7 of this SER, respectively. The staff finds that these AMPs can effectively manage the aging effects of neutron-absorbing sheets in spent fuel storage racks.

On the basis of its review, the staff finds that the applicant appropriately evaluated AMR results involving management of the reduction of neutron-absorbing capacity and loss of material due to general corrosion for components in the applicable auxiliary systems, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with the GALL Report, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.10 Loss of Material Due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion

Loss of material due to general, pitting, and crevice corrosion, and MIC could occur in the underground piping and fittings in the open-cycle cooling water system (service water system) and in the diesel fuel oil system. The Buried Piping and Tanks Inspection Program relies on industry practice, frequency of pipe excavation, and operating experience to manage the effects of loss of material from general, pitting, and crevice corrosion, and MIC. The staff reviews the effectiveness of the Buried Piping and Tanks Inspection Program, including its inspection frequency and operating experience, to ensure that loss of material is not occurring and that the components' intended function will be maintained during the period of extended operation.

The applicant credited the Buried Piping and Tanks Inspection Program with managing the identified aging effects for the applicable components in the emergency power system.
The applicant stated that the Buried Piping and Tanks Inspection Program is implemented by the Periodic Surveillance and Preventive Maintenance Program at Ginna. Tanks in the emergency power system are periodically inspected for signs of applicable aging effects. In addition, a one-time ultrasonic inspection will be performed to verify the effectiveness of the Periodic Surveillance and Preventive Maintenance Program.

The applicant further stated that, for buried piping, the Fire Water System Program is credited for managing the effects of aging for buried cast iron piping and fittings. External surfaces of buried piping are visually examined during maintenance activities (inspections of opportunity) performed as a result of performance tests. No evidence of age-related degradation has been detected from inspections performed to date. Cast iron fire system and service water piping at Ginna is ductile cast iron, not gray cast iron. Ductile irons are not susceptible to loss of structural integrity due to selective leaching mechanisms and generally display excellent resistance to general corrosion due to exposure to nonaggressive ground water. Ground water/lake water at Ginna is analyzed periodically, and analyses performed to date confirm that the water is nonaggressive. The staff evaluation of the Buried Piping and Tanks Inspection, Periodic Surveillance and Preventive Maintenance, One-Time Inspection, and Fire Water System Programs is documented in Sections 3.3.2.3.1, 3.0.3.8, 3.0.3.7, and 3.3.2.3.3 of this SER, respectively. The staff finds that these AMPs can effectively manage the aging effects for the above components that are applicable to Ginna auxiliary systems.

On the basis of its review, the staff finds that the applicant appropriately evaluated AMR results involving management of the loss of material due to general, pitting, crevice, and MIC, for components in the auxiliary systems, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with the GALL Report, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.11 Conclusions

The staff has reviewed the applicant's evaluation of the issues for which GALL recommends further evaluation for components in the auxiliary systems. On the basis of its review, the staff finds that the applicant has provided sufficient information to demonstrate that the issues for which the GALL Report recommends further evaluation have been adequately addressed and that there is reasonable assurance that the subject aging effects will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3). In addition, the staff concludes that the applicant's UFSAR Supplement provides an adequate description of the programs credited with managing these aging effects, as required by 10 CFR 54.21(d).

3.3.2.3 Aging Management Programs (System-Specific)

In SER Sections 3.3.2.1 and 3.3.2.2, the staff determined that the applicant's AMRs and associated AMPs will adequately manage component aging in the auxiliary systems. The staff then reviewed specific components in the auxiliary systems to ensure that they were properly evaluated in the applicant's AMR.

To perform its evaluation, the staff reviewed the components listed in LRA Tables 2.3.3-1 through 2.3.3-20 to determine whether the applicant had properly identified the applicable AMRs and AMPs needed to adequately manage the aging effects for the components. This portion of the staff review involved identification of the aging effects for each component, ensuring that each aging effect was evaluated using the appropriate AMR in Section 3, and that management of the aging effect was captured in the appropriate AMP. The results of the staff's review are provided below.

The staff also reviewed the UFSAR Supplements for the AMPs credited with managing aging in reactor system components to determine whether the program description adequately describes the program.

The applicant credits 19 AMPs with managing the aging effects associated with components in the auxiliary systems. Eleven of the AMPs are credited with managing aging for components in other system groups (common AMPs), while the other 8 AMPs are credited with managing aging only for auxiliary system components. The staff's evaluation of the common AMPs credited with managing aging in auxiliary system components is provided in Section 3.0.3 of this SER.

The common AMPs are listed below along with their section number:

- Water Chemistry Program (3.0.3.1)
- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program (3.0.3.2)
- Bolting Integrity Program (3.0.3.3)
- Boric Acid Corrosion Prevention Program (3.0.3.4)
- Closed-Cycle (Component) Cooling Water System Program (3.0.3.5)
- Flow-Accelerated Corrosion Program (3.0.3.6)
- One-Time Inspection Program (3.0.3.7)
- Periodic Surveillance and Preventive Maintenance Program (3.0.3.8)
- Selective Leaching of Materials Program (3.0.3.9)
- Structures Monitoring Program (3.0.3.10)
- System Monitoring Program (3.0.3.11)

The staff's evaluation of the eight auxiliary system AMPs is provided in the following sections.

3.3.2.3.1 Buried Piping and Tank Inspection Program

3.3.2.3.1.1 Summary of Technical Information in the Application. The applicant describes its AMP for buried piping and tank inspection in Section B2.1.7 of the LRA. The applicant stated that this program is not specifically used for aging management at Ginna since the inspection activities under the scope of this program in NUREG-1801 (GALL) are managed by the One-Time Inspection Program.

The applicant stated that preventive measures to mitigate corrosion on the buried carbon steel piping and tanks were applied in accordance with standard industry practice for maintaining protective coatings. The buried piping and tanks will be inspected when the opportunity of inspection arises, such as during excavation for maintenance activities.

The applicant described the following operating experience with the buried piping and tanks:

- Over the years, several sections of the firewater loops have been inspected and replaced with upgraded materials.

- In 1974, a section of the service water discharge header from the auxiliary building was inspected.

- In 1995, portions of the underground service water header were inspected.

- In 2001, a yard hydrant and connecting piping and a security diesel generator underground fuel oil storage tank were replaced.

The exterior surface conditions of these components, whether inspected or replaced, were all in good condition.

3.3.2.3.1.2 Staff Evaluation. In its response to the staff's RAI (RAI B2.1.7.1-a), the applicant stated that the Buried Piping and Tanks Inspection Program implemented at Ginna is consistent with the guidelines provided in NUREG-1801 (GALL Report), AMP XI.M34. No exception to GALL AMP XI.M34 was identified. The NRC audit team reviewed the subject program at the plant site and confirmed that the subject program is consistent with GALL AMP XI.M34.

The staff finds that the inspection activities of buried piping and tanks are not identified in the One-Time Inspection Program. In its response to RAI B2.1.7.1-e, the applicant stated that the inspections of buried piping and tanks is now included in the One-Time Inspection Program. In its response to RAI B2.1.7-1 and RAI B2.1.8-1, the applicant described the past inspections performed on the buried components, and the inspection results are summarized below.

- The technical support center (TSC) underground diesel storage tank, a carbon steel tank installed in 1980, was excavated to repair the mechanical damage of the vent pipe in 1998. The exterior surface of the tank, coated with an asphaltic coal tar protective coating, was found to be in excellent condition.
- The security diesel storage tank is not in scope for LRA but is similar in construction to the TSC diesel storage tank. This tank was dug up and replaced in 2000. Both the internal surfaces of the tank and the exterior protective asphaltic coating were in excellent condition after 30 years of service.
- The underground portion of the service water piping at Ginna is made of pre-stressed concrete. In 1994, a remote visual inspection of the interior of approximately 500 feet of this piping was performed. In addition, the exterior of a portion of the concrete service water pipe was visually inspected during the construction of the diesel generator building in 1992. The results of the inspections showed that the subject underground concrete piping was in excellent condition.
- The fire water system piping at Ginna is made of cement-lined ductile cast iron with an external protective coating of coal tar. Visual inspection of the external and interior surfaces of the piping performed during maintenance activities showed that the subject underground piping was in excellent condition.
- The EDG diesel fuel oil storage tanks are carbon steel tanks with a protective external coal tar mastic coating. The interiors of these tanks are cleaned, visually inspected, and ultrasonically measured for wall thickness under the Periodic Surveillance and Preventive Maintenance Program on a 9-year frequency. These inspections did not report any evidence of degradation.

Based on the inspection results and service experience of the buried components discussed above, the staff agrees with the applicant that the buried environment at Ginna is benign, and therefore, extra mitigation measures such as the installation of a cathodic protection system and augmented inspections, in addition to the One-Time Inspection Program, are not necessary.

The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program. The staff finds the subject supplement acceptable.

3.3.2.3.1.3 Conclusions. On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with GALL. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.3.2.3.2 Fire Protection Program and Fire Water System Program

3.3.2.3.2.1 Summary of Technical Information in the Application. The applicant's AMP for fire protection (FP) systems is discussed in LRA Sections B2.1.13, "Fire Protection," and B2.1.14, "Fire Water System." The Ginna Fire Protection Program includes provisions for aging management of fire barriers and fire pumps. The Fire Barrier Inspection Program requires periodic visual inspection and functional tests of fire barrier penetration seals, fire barrier walls, ceilings, and floors, and periodic visual inspection and functional tests of fire-rated doors to ensure their operability is maintained. The program also requires the fire pumps to be periodically tested, with preventive maintenance and inspections performed to ensure their operability. The program also provides for periodic inspection and testing of the relay room Halon fire suppression system.

The Ginna Fire Water System Program includes provisions for aging management of the fire water system and associated components. These components include sprinklers, nozzles, fittings, hydrants, hose stations, standpipes, fire water storage tank, fire booster pump, etc. System and component testing is conducted in accordance with the applicable National Fire Protection Association (NFPA) codes and standards. The fire water system and associated components are normally maintained at required pressure and monitored such that a loss of system pressure is immediately detected and corrective actions initiated. In addition to the testing performed per NFPA codes, portions of the fire water system are subjected to full flow testing. Also, internal portions of the fire water system are visually inspected when disassembled for maintenance. Volumetric NDE inspections using appropriate techniques are performed on sections of the system piping to detect wall loss and fouling. The flow testing and visual and/or volumetric inspections assure that any wall thinning due to corrosion, MIC, or biofouling are managed such that the system function is maintained. The applicant concluded that the Ginna Fire Water System Program is consistent with NUREG-1801, Section XI.M27, and that a review of previous inspection and maintenance records provides reasonable assurance that the fire water system remains capable of performing its intended function. The program will be enhanced to provide testing and, if necessary, replacement of sprinkler heads after 50 years in service, in accordance with the requirements of NFPA 25. The applicant further concludes that the aging effects for the fire water system and associated components will be managed such that the intended function of the components within the scope of the program will be maintained during the license renewal period.

Table 3.4.1 of the LRA, line 6, identifies the AMP for the reactor coolant pump oil collection system as covered by the One-Time Inspection Program.

3.3.2.3.2.2 Staff Evaluation. The staff reviewed the program outlined in LRA Appendix B2.1.13 and B2.1.14 and UFSAR Supplement program descriptions in LRA Appendix A2.1.10 and A2.1.11. Based on the reviews of these LRA appendices, no exceptions to GALL were identified.

The AMP audit performed on June 23–25, 2003, identified a discrepancy between the LRA and the applicant's Fire Protection Program basis document, LR-FP-PROGPLAN. The LRA states that the Fire Protection Program is consistent with GALL, whereas the basis document states that the AMP is consistent with GALL with discrepancies. The applicant was asked to provide the basis for the discrepancies in GALL and LR-FP-PROGPLAN identified during the AMP audit. The applicant responded that the Fire Protection Program is consistent with, but includes exceptions to, NUREG-1801, Section XI.M26, “Fire Protection.” The exceptions identified are as follows.

Halon system testing frequency is different from the 6-month frequency stated in NUREG-1801. The applicant was requested to clarify the testing frequency and justify the exception. The applicant responded that the testing is based upon a performance-based evaluation of system components documented in DA-ME-97-081, “Engineering Evaluation of Fire Protection System Inspection and Testing,” February 10, 2000. This evaluation justifies a frequency of every 2 years for the functionality of the system. The DA-ME-97-081 report also applies to the aging management aspect of system components. When functional tests are performed, both the active and passive portions of the system are tested. The manual and automatic operation of the Halon system would not be successful without an intact pressure boundary, or with material conditions that could adversely affect the performance of the system. Corrosion, mechanical damage, or damage to dampers would all hinder successful performance of the functional tests.

Visual inspections of fire doors and verification of clearances are performed on a quarterly basis, not bimonthly as stated in NUREG-1801. The applicant was requested to verify, based on plant experience, that these frequencies are adequate for aging management concerns related to fire doors. In a letter dated September 16, 2003, the applicant responded with the following:

> The aging management issues of concern for fire doors, as noted in NUREG-1801, are clearances, and holes in the skin. A review of our quarterly fire door walkdown operating experience indicates that these issues have not been of concern. It is thus considered that the quarterly frequency established for inspections of fire doors are adequate for aging management.

Personnel performing inspections of fire barriers, doors, and penetration seals are qualified to perform those inspections in accordance with plant procedures QC-INS-2 “Qualification of Inspection Personnel” and A-1102 “Qualification and Certification of Test Personnel,” but not necessarily in accordance with the requirements for VT-1 or VT-3 as defined in RG&E NDE procedure NDE-102. The staff considers these qualifications to be adequate for the aging management inspections of fire barriers, doors, and penetration seals, on the basis that these inspections have clearly identified acceptance criteria and require no special tools.

As stated in Section 2.3.3.6 of this SER, the applicant was asked to clarify the aging management for the buried underground piping portions of the fire water system in RAI 2.3.3.6-2. As discussed in that SER section, the applicant’s response described the testing and inspection efforts that provide the basis for this AMP. The AMP audit performed on June 23–25, 2003, also identified a discrepancy between the LRA and the applicant's Fire Water System Program basis document, LR-FWS-PROGPLAN. The LRA states that the Fire Water System Program is consistent with GALL, whereas the basis document states that the AMP is consistent with GALL with discrepancies. The applicant was asked to provide the basis for the discrepancies in GALL and LR-FWS-PROGPLAN identified during the AMP audit. The exceptions identified are as follows.

In the program basis document, the applicant stated that the parameters monitored/inspected attribute includes exceptions to the GALL AMP related to periodic flow testing of infrequently used loops. The audit team identified differences in the Detection of Aging Effects attribute. The sprinkler system components are not examined for evidence of microbiological fouling as indicated by GALL. In addition, GALL recommends visual inspections of yard fire hydrants to be performed every 6 months, whereas the basis document specifies during windows of opportunities during maintenance activities. The GALL Report also specifies that fire hydrant flow tests be performed annually, while the basis document specifies on a periodic basis. The applicant was requested to provide the basis for these exceptions to GALL. In a response dated September 16, 2003, the applicant stated the following:

- Sprinkler system components at Ginna Station are examined for evidence of biological fouling. As indicated in the revised Fire Water System Program basis document, these inspections are performed by RT and UT. Radiographic inspections are capable of detecting biological fouling, wall thinning, and sedimentation in fire water system piping.

- As indicated in the revised Fire Water System Program basis document, Section 4.0, visual inspections of yard fire hydrants are performed twice per year, which is reasonably consistent with NUREG-1801.

- As indicated in the revised Fire Water System Program basis document, Section 4.0, fire hydrants are flushed annually at Ginna Station by opening each hydrant fully and verifying (qualitatively) adequate flow. Flow test and performance trending data are collected every 3 years. The 3-year frequency is supported by plant-specific operating experience (DA-ME-97-081) and industry practice.

Various sections of fire protection system piping are selected annually for NDE inspection and verification of wall thickness requirements. Inspections of various headers will be performed each operating cycle using UT or RT techniques. These inspections are driven by a “Repetitive (Rep) Task” in the Periodic Surveillance and Preventive Maintenance Program. The selection criteria, sample size, and periodicity of these inspections during the period of extended operation, including the expansion criteria in the event that age-related degradation is found, will be defined prior to the end of the current license period (reference item 30 in Appendix A to this SER). Testing of individual fire systems verifies that piping up to deluge valves is free of obstructions.

The exterior condition of the underground fire system piping is verified by inspections performed under the Buried Piping and Tanks Inspection Program, “LR-BTNK-PROGPLAN.” Sprinkler systems are inspected and tested as defined in the procedures listed in Section 4.0 to ensure that degradation is detected in a timely manner.

This element is consistent with, but contains an exception to, the corresponding AMP attribute in the GALL Report, Section XI.M27. The GALL Report states that sprinkler systems are to be inspected once every refueling outage. Sprinkler system headers and spray heads be inspected every 2 years at Ginna Station in accordance with the Technical Requirements Manual (TRM). The 2-year frequency is supported by plant-specific operating experience and is based upon the analysis in DA-ME-97-081. In addition, the GALL Report states that fire hydrant flow tests are to be performed annually. Fire hydrants are flushed annually at Ginna Station by opening each hydrant fully and verifying (qualitatively) adequate flow. Flow test and performance trending data are collected every 3 years. The 3-year frequency is supported by plant-specific operating experience and industry practice. Therefore, the intent of GALL, Section XI.M27, paragraph 5.4, is met. On the basis of the applicant’s response, the staff concurs that the Fire Water System Program provides adequate aging management for the underground fire water piping.

The One-Time Inspection Program outlined in B2.1.21 is applied to the reactor coolant pump oil collection system. This program is adequate for controlling the potential aging effects on the oil collection system components.

3.3.2.3.2.3 <u>Conclusions</u>. On the basis of its review and audit of the applicant’s program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with GALL. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.3.2.3.3 Fire Water System Program

See Fire Protection Program and Fire Water System Program (3.3.2.3.2).

3.3.2.3.4 Fuel Oil Chemistry Program

3.3.2.3.4.1 Summary of Technical Information in the Application. The applicant's Fuel Oil Chemistry Program is discussed in LRA Section B2.1.16, "Fuel Oil Chemistry." The applicant stated that the program is consistent with GALL Program XI.M30, "Fuel Oil Chemistry," with the exceptions that the applicant does not add biocides, stabilizers, or corrosion inhibitors to the fuel oil to mitigate corrosion and does not sample for particles in accordance with the modified ASTM D2276 test procedure.

This AMP is credited with managing aging of the components exposed to the fuel oil environment and ensuring fuel oil quality.

The applicant performs surveillance and maintenance in accordance with the plant technical specifications to mitigate aging effects such as loss of material due to corrosion and fouling buildup on internal surfaces of the fuel oil tanks and associated components in the systems that contain fuel oil. Periodic draining, cleaning, and visual inspection of the internal surfaces of the storage tanks are performed, and wall thickness, if needed, is measured at the locations where the contaminants might accumulate. Review of the plant-specific operating experience confirms the effectiveness of these procedures.

In its LRA, the applicant concluded that the Fuel Oil Chemistry Program provides reasonable assurance that aging effects due to the presence of fuel oil will be adequately managed.

3.3.2.3.4.2 Staff Evaluation. In LRA Section B2.1.16, "Fuel Oil Chemistry," the applicant describes its AMP to manage aging of the components exposed to the fuel oil environment. The LRA states that this AMP is consistent with GALL AMP XI.M30, "Fuel Oil Chemistry," with exceptions regarding not adding biocides, stabilizers, or corrosion inhibitors to the fuel oil and not sampling for particles in accordance with the modified ASTM D2276 test procedure.
In letters dated May 13 and June 10, 2003, the applicant, responding to RAI B2.1.16-1, stated that in a review of plant-specific operating experience, no evidence of oil degradation or MIC has ever been observed. Therefore, addition of biocides, stabilizers, or corrosion inhibitors has not been needed to date. The effectiveness of using fuel oil without additives will be verified by the results of periodic inspections of the fuel storage tanks. In its letter, the applicant also modified its position regarding measuring particles and applying the "clear and bright" method for determining water and particulate contamination in the diesel fuel oil and committed to change the technical specifications. This was Confirmatory Item 3.3.2.3.4-1. In a letter dated December 9, 2003, the applicant made a commitment (reference item 40 in Appendix A to this SER) to submit a technical specification change by the end of 2004, to incorporate specific particulate testing requirements for diesel generator fuel oil in accordance with the ASTM D2276 standard or its successor, and eliminate the need for the "clear and bright" method of the ASTM D4176 standard. This resolves Confirmatory Item 3.3.2.3.4-1.

During the AMP audit, the staff confirmed the applicant's claim of consistency with the GALL program and determined that the program was properly applied to the Ginna facility. Furthermore, since the applicant committed to include in its Fuel Oil Chemistry Program a particle testing requirement, the only remaining deviation from the GALL program consists of not adding biocides and corrosion stabilizers to the fuel oil. The staff reviewed the deviation and its justification to determine whether the AMP, with this deviation, could manage the aging effects for which it is credited. The staff's review has indicated that the AMP could adequately manage these effects. In addition, the staff reviewed the UFSAR Supplement to determine whether it provides an adequate description of the revised program and found it to be acceptable, as required by 10 CFR 54.21(d).

3.3.2.3.4.3 Conclusions. On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with GALL. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.3.2.3.5 Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program

3.3.2.3.5.1 Summary of Technical Information in the Application. The applicant's inspection of overhead heavy load and light load handling systems is discussed in LRA Section B.2.18, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems." The applicant stated that the program is consistent with GALL Program XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems."

The testing and monitoring programs are implemented to ensure that cranes are capable of sustaining their rated loads. Many components of a crane system perform their intended functions with moving parts or with a change in configuration or are subject to replacement based on qualified life. These components are screened out of the license renewal aging management process. This program is primarily concerned with structural components that make up the bridge, trolley, rails, stops, and lifting devices.

NUREG-1774, "A Survey of Crane Operating Experience at U.S. Nuclear Power Plants from 1968 through 2002," dated July 2003, provides a comprehensive assessment of crane issues. There have been numerous crane incidents, some of which resulted in the publication of NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants." The applicant stated that most crane failures are caused by human error (not following procedures, improper test) or design issues (poor engineering). Less than 10 percent of failures were due to improper maintenance, and most of these were due to electrical malfunctions. According to the applicant, there is very little history of wear-related or corrosion-related degradation that has impaired the ability of cranes in the industry to perform their intended functions. A re-evaluation of crane operations by the applicant based on Bulletin 96-02, "Movement of Heavy Loads over Spent Fuel, over Fuel in the Reactor Core, or over Safety-Related Equipment," dated April 11, 1996, concluded that although there were some inconsistencies between crane operation and the licensing basis at some nuclear power plants, few changes were required by licensees in their operation of cranes (and none related to age-related degradation).

According to the applicant, only one major crane failure has occurred at Ginna. During plant construction, a portion of the reactor vessel internals weighing 90 tons was dropped about 6 feet. The cause of failure was attributed to a crane brake failure (crane motor overheated and the electromagnetic brake failed). No experience with crane failures due to age-related degradation such as wear or corrosion has occurred at Ginna according to the applicant.

In the LRA, the applicant concluded that the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program provides assurance that the intended functions of the cranes will be met during the period of extended operation.

3.3.2.3.5.2 Staff Evaluation. In LRA Section B. 2.18, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems," the applicant described its program to manage the aging of overhead heavy loads and light load handling systems within the scope of license renewal. The LRA states that this program is consistent with GALL Program XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems." The staff confirmed the applicant's claim of consistency during the AMP audit. In addition, the staff determined whether the applicant properly applied the GALL program to its facility. The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program.

LRA Section B2.1.18 states that some inconsistencies were identified between crane operation and crane licensing basis at some plants in Bulletin 96-02, "Movement of Heavy Loads over Spent Fuel, over Fuel in the Reactor Core, over Safety-Related Equipment." In RAI B2.1.18-1, the staff requested the applicant to indicate whether or not any such inconsistencies have been identified at Ginna, either before or after the issuance of Bulletin 96-02. If inconsistencies were identified, it was requested that the applicant provide the corrective actions that were taken.

In its response, dated May 28, 2003, the applicant stated that no inconsistencies were identified at Ginna. In its response to Bulletin 96-02, dated May 10, 1996, the applicant had stated that "all potential heavy load movements are within the scope of the Ginna Station licensing basis and are covered by existing plant procedures and work control…" The NRC's SER of April 23, 1998, agreed with this assessment. The staff finds the applicant's response acceptable because it confirms the applicant's claim of consistency with Bulletin 96-02.

In RAI B2.1.18-2, the staff requested the applicant to clarify whether wire ropes are among the subcomponents that are managed for age-related degradation. The applicant was also requested to provide the inspection methods and acceptance criteria for the wire ropes.

In its response, dated May 28, 2003, the applicant referred to Section 2.3.3.11 of the LRA which states that cables, hooks, and moving load-bearing elements used for transport of heavy loads are within the scope of license renewal. Inspection methods and acceptance criteria are provided in Ginna procedure MHE-201, “Overhead and Gantry Cranes.” These are visual inspections for evidence of wear, discontinuities, and any other signs of aging conducted by personnel qualified in accordance with procedure MHE-101, “Classification and Training of Material Handling Equipment Personnel.” The staff finds the applicant's response acceptable because it clarifies that wire ropes are managed for aging as required by the GALL Report.

3.3.2.3.5.3 Conclusions. On the basis of its review and audit of the applicant’s program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with GALL. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.3.2.3.6 Open-Cycle Cooling Water System Program

3.3.2.3.6.1 Summary of Technical Information in the Application. The applicant’s open-cycle cooling water system is discussed in LRA Section B2.1.22, “Open-Cycle Cooling (Service) Water System.” The applicant stated that the program is consistent with GALL Section XI.M20 Open-Cycle Cooling Water System with two exceptions. First, heat transfer tests are not performed on selected small heat exchangers that are periodically cleaned and inspected in accordance with the Periodic Surveillance and Preventive Maintenance Program, and second, the Service Water System Reliability Optimization Program does not address protective coatings.

This AMP is credited with managing the aging effects of loss of material due to corrosion and/or buildup of deposits due to biofouling in the ESF systems and loss of material due to general, pitting, crevice, and galvanic corrosion, MIC, and buildup of deposits due to biofouling in the auxiliary systems and SPCS.

The applicant developed the Service Water System Reliability and Optimization Program which implements the recommendations of GL 89-13, “Service Water System Problems Affecting Safety-Related Equipment,” to ensure that the effects of aging on the service water system will be managed for the period of extended operation. The program includes surveillance and control techniques to manage aging effects caused by biofouling, corrosion, erosion, and silting in the service water system or structures and components serviced by the service water system.

The applicant's operating experience indicates that implementation of the recommendations of GL 89-13 during the past 10 years has been effective at managing and monitoring the effects of aging due to biofouling, corrosion, erosion, and silting in the service water system.
The applicant has found Zebra mussels and has experienced corrosion, pitting, MIC, and sedimentation buildup in the service water system. These effects are controlled by flushing the chlorination system and inspections.

On the basis of the above discussion, the applicant concluded that the Service (Open-Cycle Cooling) Water System Program provides reasonable assurance that the aging effects of the service (open-cycle cooling) water system will be adequately managed for the period of extended operation.

3.3.2.3.6.2 Staff Evaluation. In LRA Section B2.1.22, "Open-Cycle Cooling (Service) Water System," the applicant described its AMP to manage aging in the service water system.
The applicant's LRA stated that this AMP is consistent with GALL AMP XI.M20, Open-Cycle Cooling Water System, with two exceptions—(1) heat transfer tests are not performed on selected small heat exchangers that are periodically cleaned and inspected in accordance with the Periodic Surveillance and Preventive Maintenance Program, and (2) the Service Water System Reliability and Optimization Program does not address protective coatings. The staff confirmed the applicant's claim of consistency during the AMP audit that was performed June 23–25, 2003. The staff reviewed the exceptions and their justification to determine whether the AMP, with the deviations, remains adequate to manage the aging effects for which it is credited and reviewed the UFSAR Supplement to determine whether it provides an adequate description of the revised program.

By letter dated March 21, 2003, the staff requested additional information regarding the applicant's exceptions to the program. The applicant responded to the RAIs in a letter dated May 13, 2003, and provided a clarifying response to one of the original RAIs in a letter dated July 11, 2003.

In RAI B2.1.22-1, the staff asked the applicant to provide additional information regarding the first exception that heat transfer tests are not performed on selected small heat exchangers that are periodically cleaned and inspected in accordance with the Periodic Surveillance and Preventive Maintenance Program. The additional information requested regarded the criteria used to scope/identify these small heat exchangers, the parameters monitored/inspected during the preventive maintenance action, how aging is detected, how periodicity is established, trending of results, and what acceptance criteria are used. The staff also requested a discussion relative to if and how enhancements needed for the Periodic Surveillance and Preventive Maintenance Program (identified in the applicant's LRA Section B.2.1.23) to be consistent with the GALL Report would impact these heat exchangers.

The applicant indicated the guidance provided by GL 89-13 is used to identify small heat exchangers that will be periodically cleaned and inspected. Plant-specific operating experience is used by the applicant to establish the periodicity of these maintenance activities which may employ visual inspection, eddy current testing, thermal performance testing, bench marking, and differential pressure testing to detect the effects of aging. Eddy current testing is performed in accordance with plant procedures, and the results are compared to previous inspections in order to identify fretting at tube support locations, pitting, SCC, and erosion. The acceptance criteria for eddy current testing are a function of wall thinning, defect size, and tube plugging limits. When thermal performance testing is employed, the results are analyzed by engineering personnel to determine the level of fouling. The applicant indicated that enhancements will be incorporated into plant procedures implementing the visual inspections and will include specific guidance on detection of aging effects. Inspection data from eddy current testing and visual examinations are trended by the applicant under the Periodic Surveillance and Preventive Maintenance Program.

The staff found the applicant's response acceptable based on the applicant's use of guidance provided by GL 89-13 regarding the management of aging mechanisms for small heat exchangers.

The other exception identified by the applicant was that the Service (Open-Cycle Cooling) Water System Program does not address protective coatings. The staff noted that failed internal protective coatings could lead to a loss of heat transfer or to corrosion. In RAI B2.1.22-2, the staff requested information regarding how the applicant ensures internal coating failure (if any coatings are used) will not adversely impact heat transfer capability or corrosion of system components and asked the applicant to provide operating experience supporting the applicant's position. The applicant responded that essentially there are no internal coatings in the service (open-cycle cooling) water system. Only the interior surfaces of the service water pump bowls are coated with an abrasion-resistant coating. These pumps were first internally coated in 1999. The first internal inspection is planned for the fall of 2003. The plant has no operating experience indicative of pump bowl coating failure.

The staff finds the applicant's exception relative to management of internal coatings within the service (open-cycle cooling) water system acceptable based on the limited amount of internal coatings at the time of the review.

The applicant's service water system operating experience discussion indicated that a number of plant heat exchangers had been replaced or retubed. The staff requested additional information in RAI B2.1.22-3 regarding the degradation mechanisms, means of identification, if loss of pressure boundary occurred, and if changes to the program resulted from this operating experience.

The applicant indicated that a number of heat exchangers with admiralty brass tubes, which fell within the scope of license renewal, had been retubed. Periodic eddy current testing under the Periodic Surveillance and Preventive Maintenance Program as implemented by the Open Cycle Cooling Water System program is used to detect degradation. The degradation mechanisms identified by eddy current testing and verified by destructive metallurgical examination have included thinning due to erosion/corrosion, pitting and under-deposit corrosion, and limited outside diameter fretting due to flow-induced vibration. Tubes were removed from service by plugging based on conservative criteria, and no loss of pressure boundary integrity has occurred in any of these heat exchangers. The heat exchangers were retubed with admiralty brass when the number of tubes plugged approached tube plugging limits. The applicant indicated that in some cases the inspection frequency has been increased based on the program's operating experience.

The applicant also noted that certain heat exchangers within the scope of license renewal are periodically replaced/refurbished. These coolers are removed from service on a fixed frequency, cleaned, eddy current inspected, and replaced in stock for reuse. The periodicity of the refurbishment activity is based on plant-specific operating experience related to tube-side fouling. The tubes are stainless steel and no corrosion-related tube-wall degradation has ever been detected.

The staff finds that the applicant's additional operating experience for heat exchangers, which have been retubed or are periodically removed from the system and refurbished, provides objective evidence that the program will adequately manage aging during the period of extended operation.

3.3.2.3.6.3 Conclusions. On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with GALL. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.3.2.3.7 Spent Fuel Pool Neutron Absorber Monitoring Program

3.3.2.3.7.1 Summary of Technical Information in the Application. The applicant's Spent Fuel Pool Neutron Absorber Monitoring Program is discussed in LRA Section B2.1.30, "Spent Fuel Pool Neutron Absorber Monitoring." The applicant stated that the program does not have a corresponding AMP in the GALL Report because at Ginna, the active neutron absorber material consists of borated stainless steel instead of Boraflex. The applicant described, therefore, the program in terms of 10 program elements.

This AMP is credited with managing aging of the neutron absorber in the spent fuel pool. The aging effect this AMP is intended to manage is loss of boron from the borated steel panels.

The applicant performed an inspection of the absorber material under the Ginna Spent Fuel Pool Neutron Absorber Monitoring Program. Borated steel panels were monitored using surveillance coupons composed of the same material. These coupons underwent periodic examinations consisting of visual inspections, thickness and weight measurements, and comparison of the resultant data to the reference samples that have not been exposed to the spent fuel pool environment. These examinations provide timely information on the condition of the neutron-absorbing panels. The applicant's review of the monitoring results indicates that the stainless steel neutron absorber panels exhibit good corrosion resistance in the fuel pool environment and will perform their function over the remaining life of the spent fuel racks.

In its LRA, the applicant concluded that the Spent Fuel Pool Neutron Absorber Monitoring Program ensures that aging effects of the borated stainless steel panels will be adequately managed.

3.3.2.3.7.2 Staff Evaluation. In LRA B2.1.30, "Spent Fuel Pool Neutron Absorber Monitoring," the applicant described its AMP to manage aging of the spent fuel pool neutron absorber. Since there was no corresponding AMP in the GALL Report, the staff reviewed this AMP against the 10 program elements using the guidance in Branch Technical Position RLSB-1 in Appendix A.1 to the SRP-LR. The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program.

The staff evaluation of the Spent Fuel Pool Neutron Absorber Monitoring Program focuses on how the activities manage aging effects through the effective incorporation of the 10 program elements.

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 Appendix B to 10 CFR Part 59, and cover all structures and components subject to AMR. The staff evaluation of the applicant's Quality Assurance Program is provided separately in Section 3.0.4 of this SER. This program satisfies the elements of corrective actions, confirmation process, and administrative controls. The remaining seven elements are discussed below.

Program Scope. The program monitors long-term performance of the borated stainless steel panels used to control reactivity in the spent fuel pool by absorbing neutrons. The panels are monitored by using surveillance coupons made of the same material. The staff finds that including this type of surveillance in the scope of the Spent Fuel Pool Neutron Absorber Monitoring Program will satisfy the objectives of the program.

Preventive Actions. The applicant stated that the Spent Fuel Pool Neutron Absorber Monitoring Program is a monitoring program and does not specify preventive actions. The staff concurs with the applicant's statement.

Parameters Monitored/Inspected. The aging effects of the borated stainless steel neutron absorbers are monitored by examining coupons made from the same materials and placed in the spent fuel pool. The examination consists of visual inspection, thickness measurement, and weighing. The staff concurs with the applicant that this type of inspection of the coupons will provide meaningful information regarding aging of the spent fuel pool neutron absorbers.

Detection of Aging Effects. The aging effect of neutron absorbers in the spent fuel pool consists of a loss of boron from the borated steel panels which could be predicted by a change of boron content in the coupons. The staff finds that the applicant's procedure for measuring boron content provides a valid method for detection of the aging effect in the spent fuel pool neutron absorber.

Monitoring and Trending. The coupons are evaluated at different time intervals, and the results are recorded as directed by the site-specific procedures. According to the schedule, the first evaluation is performed after completion of the first operating cycle following installation of the racks. The subsequent evaluations are performed after completion of every third additional cycle. The staff finds that this procedure will allow the applicant to adequately monitor and trend the aging effects in the spent fuel pool neutron absorbers.

Acceptance Criteria. The acceptance criteria consist of comparing the data determined during the coupons inspections to the reference values. The staff finds that this procedure will allow the applicant to determine if the borated stainless steel panels have enough boron to control reactivity in the spent fuel pool.

Operating Experience. The applicant stated that the examination of the first set of coupons showed no evidence of signs of degradation. This indicated to the staff that borated stainless steel neutron absorber panels exhibited good corrosion resistance and their neutron-absorbing capability is not impaired.

3.3.2.3.7.3 Conclusions. On the basis of its review of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with GALL. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.3.2.3.8 Aboveground Carbon Steel Tanks Program

3.3.2.3.8.1 Summary of Technical Information in the Application. The applicant describes its AMP for aboveground carbon steel tanks in Section B2.1.1 of the LRA. Periodic system walkdowns will be performed to monitor the condition of aboveground carbon steel storage tanks. For tanks supported on earthen or concrete foundations, the tank bottom is inaccessible for inspection. For such tanks, one-time thickness measurements of the tank bottom will be performed from inside of the tank to assess the tank bottom condition.

The applicant reported the following operating experience for aboveground carbon steel tanks:

- Isolated areas of degradation (flaking and peeling of paint) were discovered on tanks inside the containment, but the quantity was small and would not cause plugging of the sump screens.

- For tanks outside the containment, no significant corrosion of the tank outside surfaces was reported.

The applicant concludes that with the implementation of one-time inspection and continued inspection and surveillance activities through the Systems Monitoring Program, there is assurance that age-related degradation of external surfaces of aboveground carbon steel tanks will be adequately managed during the period of extended operation.

3.3.2.3.8.2 Staff Evaluation. In response to RAI B2.1.1-1-a, the applicant stated that the Aboveground Carbon Steel Tanks Program implemented at Ginna is consistent with the guidelines provided in GALL AMP XI.M29, with one exception. The exception is that the protective coatings, although used on carbon steel tanks, are not credited with mitigating the effects of aging. During the AMP audit, the staff confirmed the applicant's claim of consistency for those attributes that were claimed to be consistent with GALL.

In its response to C-RAI B2.1.1-1, the applicant stated that all tanks in the scope of this program are protectively coated at exterior surfaces. Therefore, the staff finds that the applicant's exception to the GALL program in not crediting the protective coatings as a preventive measure is a moot point because the applied coating will provide a mitigation effect in reducing the rate of corrosion of the tank exterior surface, irrespective of whether the applicant takes credit for the protective coatings or not. In addition, the coatings are inspected during the systems engineer's walkdowns. If degradation is noted, the condition of the coatings, including its effect on tank surface, will be evaluated, and the condition will be corrected when considered necessary. Therefore, the staff finds that the applicant's exception to the GALL program is acceptable because it would not have any impact on the mitigating effect of the coatings already applied.

The staff finds that the bottom thickness measurement of the aboveground carbon steel tanks with inaccessible tank bottoms is not identified in the scope of the One-Time Inspection Program. In its response to RAI B2.1.1-1-c, the applicant stated that ultrasonic thickness measurements of the bottom surfaces of aboveground carbon steel tanks are now included in the scope of the One-Time Inspection Program.

In RAI B2.1.1-1-d, the staff recommends that appropriate guidance be provided in the program for selecting locations with the highest likelihood of corrosion problems for thickness measurements, such as the locations where there is observed degradation of sealant or caulking at the interface edge between the tank and foundation, which would allow penetration of water and moisture and cause corrosion of the bottom surface. In its response to the staff's RAI, the applicant stated that such guidance is now provided in the Aboveground Carbon Steel Tanks Program.

In RAI B2.1.1-1-e, the staff recommends that the guidance for sample expansion and increasing frequency of inspection be provided in this program when surface degradation is observed. In its response to the staff's RAI, the applicant stated that guidance for additional measurements and inspections in the event that degradation is detected is now provided in the Aboveground Carbon Steel Tanks Program. In addition, the guidance for corrective action would include additional inspections to assess the rate of degradation, repair to the inside coating if needed, repair to the tank wall if minimum wall thickness requirements are not met, or other measures as determined by an engineering evaluation.

In its response to RAI B 2.1.1-1.b, the applicant provided the following information regarding the inspection results and the scheduled inspection for the aboveground carbon steel tanks that are in the scope of the LRA:

- In 2001, a thorough inspection of the reactor makeup water storage tank was performed. The flat bottom head of the tank rests directly on the concrete floor. The inspection consisted of visual examination of the interior surfaces of the tank and ultrasonic thickness measurements of the tank bottom. The inspection results showed that the interior coating was in excellent condition and there was no loss of material at the tank bottom.

- The flat-bottomed “A” and “B” EDG fuel oil day tanks and the TSC diesel generator fuel oil day tank are flat-bottomed tanks, mounted on pedestals. These tanks, including the exterior surface of the tank bottoms, will be inspected during the 2003 refueling outage.

- The flat-bottomed “A” and “B” condensate storage tanks are mounted on the concrete floor. These tanks will be drained and inspected including ultrasonic thickness measurements of the tank bottoms during Cycle 31 (2003-2004).

- The exterior surfaces of “A” and “B” accumulator vessels and the diesel fire pump fuel oil storage tank are accessible for visual inspection during system engineer walkdowns. The interior of the accumulator vessels is clad with stainless steel.

In its response to C-RAI B2.1.1-1-d, the applicant stated that the UT thickness measurements of the bottom of the reactor makeup water tank will not be repeated prior to the period of extended operation because there is no evidence of degradation after more than 30 years of operation. Similarly for the condensate storage tanks, if no degradation is found during the 2003–2004 inspection, reinspection of the tank bottom will not be performed prior to the period of extended operation. The staff finds that the applicant's inspection plan is acceptable because the inspection results have provided reasonable assurance that the integrity of the tank bottoms will be maintained during the period of extended operation (60 years).

The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program. The staff finds the subject supplement acceptable.

3.3.2.3.8.3 Conclusions. On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with GALL. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.3.2.4 Aging Management Reviews of Plant-Specific Components

The following sections provide the results of the staff's evaluation of the adequacy of aging management for components in each of the auxiliary systems.

3.3.2.4.1 Chemical and Volume Control System

3.3.2.4.1.1 Summary of Technical Information in the Application. The description of the CVCS system can be found in Section 2.3.3.1 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3.3-1. The components, aging effects, and AMPs are provided in LRA Tables 3.4-1 and 3.4-2.

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 2.3.3-1, on pages 2-96 through 2-99, of the LRA lists individual components of the system including condenser, cooler, containment spray components, fastener (bolting), pipe, pulsation damper, pump casing, tank, temperature element, transmitter, and valve body.

For the internal environments, the LRA identifies the stainless steel and CASS exposed to treated water—borated or treated water—primary greater than 140 °F and subject to loss of material and cracking due to SCC. Carbon/low-alloy steel, stainless steel, and CASS in treated water—borated or treated water—primary less than 140 °F or treated water—other are subject to loss of material. The LRA also identifies stainless steel and copper alloy (zinc less than 15 percent) exposed to oil and fuel oil as subject to loss of material aging effects. No aging effects were identified for stainless steel, aluminum, carbon/low-alloy steel, and copper alloy (zinc less than 15 percent) exposed to air and gas.

For the external environments, the LRA identifies carbon/low-alloy steel exposed to borated water leaks or indoor not-air-conditioned environments as subject to loss of material aging effects. The LRA also identifies carbon/low-alloy steel in indoor not-air-conditioned environment as subject to loss of preload due to stress relaxation and cracking due to SCC. The LRA does not identify any aging effects for stainless steel, aluminum, cast austenitic steel, and copper alloy (zinc less than 15 percent) exposed to indoor not-air-conditioned or containment environments. The LRA states that stainless steel in the borated water leaks environment has no aging effects.

Aging Management Programs

The following AMPs are utilized to manage aging effects in the CVCS:

- Bolting Integrity Program (B2.1.5)
- Water Chemistry Program (B2.1.37)
- Boric Acid Corrosion Program (B2.1.6)
- Periodic Surveillance and Preventive Maintenance Program (B2.1.23)
- One-Time Inspection Program (B2.1.21)
- System Monitoring Program (B2.1.33)
- Closed-Cycle (Component) Cooling Water System Program (B2.1.9)

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

3.3.2.4.1.2 Staff Evaluation

Aging Effects

The staff reviewed the information in Tables 2.3.3-1, 3.4-1, and 3.4-2 for the CVCS. During its review, the staff determined that additional information was needed to complete its review.

In LRA Table 2.3.3-1, the AMR results indicated that line 5 of Table 3.4-1 is applicable to tanks, heat exchangers, and transmitters in the CVCS. However, the discussion column of Table 3.4-1, line 5, does not include the CVCS components. By letter dated March 21, 2003, the staff requested, in RAI 3.4.1-2, the applicant to clarify whether Table 3.4-1, line 5 is applicable to the tanks, heat exchangers, and transmitters in the CVCS.

In its response, dated May 13, 2003, the applicant stated that Table 3.4-1, line 5, is applicable to external surfaces of tanks, heat exchangers, and valve bodies in the CVCS. The applicant also noted that Table 3.4-1, line 5, is not applicable to transmitters.

On the basis of its review, the staff finds that the applicant’s response is acceptable because the applicant has clarified the scope of the components for which line 5 is applicable. The staff considers the issue related to RAI 3.4.1-2 to be resolved.

In LRA Table 3.4-2, line 81, for stainless steel fasteners (bolting) in the environment of borated water leaks, the applicant identified no aging effects requiring management. By letter dated

March 21, 2003, the staff requested, in RAI 3.3-3x2, the applicant to provide the basis for this determination.

In its response, dated May 23, 2003, the applicant stated that the technical basis for identifying no aging effects requiring management for stainless steel fasteners exposed to borated water leaks is found in EPRI TR-101108, “Boric Acid Corrosion Evaluation Program, Phase 1—Task 1 Report,” and in EPRI TR-104748, “Boric Acid Corrosion Guidebook.” These documents contain compilations of pertinent industry experience and summaries of corrosion test data which identify stainless steel and nickel-based alloys as alternative fastener materials which display excellent resistance to corrosion from borated water leaks.

On the basis of its review, the staff finds that the applicant’s response is acceptable because the applicant’s basis for determining no applicable aging effects is consistent with the industry experience. The staff considers the issue related to RAI 3.3-3x2 to be 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 with the environments described in Tables 2.3.3-1, 3.4-1, and 3.4-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the CVCS.

Aging Management Programs

The applicant credited the following AMPs for managing the aging effects in the CVCS:

- Water Chemistry Control Program (3.0.3.1)
- Bolting Integrity Program (3.0.3.3)
- Boric Acid Corrosion Program (3.0.3.4)
- Closed-Cycle (Component) Cooling Water System Program (3.0.3.5)
- One-Time Inspection Program (3.0.3.7)
- Periodic Surveillance and Preventive Maintenance Program (3.0.3.8)
- System Monitoring Program (3.0.3.11)

These AMPs are credited for managing the aging effects of components in several structures and systems and, therefore, are 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 common AMPs is documented in the SER sections given in parentheses above.

After evaluating the applicant’s AMR for each of the components in the CVCS, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects for this system. For those components identified in Table 3.4-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in LRA Table 3.4-2, the staff verified that the applicant credited AMPs that are appropriate for the identified aging effects.

In LRA Table 3.4-2, lines 16 and 32, the applicant credited the Closed-Cycle (Component) Cooling Water System Program with managing the aging effect of loss of material for stainless steel under treated water and other environments for various components in the auxiliary systems (e.g., boric acid evaporator condensers and coolers). However, the Closed-Cycle (Component) Cooling Water System Program does not reference EPRI TR-10736 and takes many exceptions from the GALL recommendations. By letter dated March 21, 2003, the staff requested, in RAI 3.4.1-1, the applicant to clarify how the aging effects due to corrosion product buildup, calcium deposits, and other parameters will be managed for these components.

In its response to RAI 3.4.1-1, dated May 13, 2003, the applicant stated that the Ginna Closed-Cycle (Component) Cooling Water System Program employs various methods to ensure that the components in the component cooling system will continue to perform their intended function. Periodic maintenance activities provide opportunities for visual inspections of the internal (wetted) and external surfaces of components in the system. Thermal performance testing of selected heat exchangers is used to verify that these components are capable of performing the heat removal intended function. The makeup water to CCW at Ginna Station is supplied from the reactor makeup water storage tank and thus is demineralized. Therefore, the applicant concluded that calcium and other mineral deposits are not an issue in the Ginna CCW system. The applicant stated that corrosion is controlled in the CCW system at Ginna by maintaining chromate-based inhibitors (potassium dichromate) in solution. Potassium dichromate is used because it is an excellent corrosion inhibitor and, in addition, is toxic to microbiological organisms. Monitoring of the CCW chemistry and maintaining parameters within the specified limits ensure that the system is maintained free of corrosion and biofouling.

The applicant further stated that, in addition to the activities described above, routine surveillance of system operating parameters is performed by operators during normal rounds. The surveillance includes monitoring flows through heat exchangers, monitoring system pressures at various locations, monitoring pump suction and discharge pressures, and monitoring CCW temperature and fluid temperatures in systems served by the CCW system. The combination of these activities ensures early detection of CCW system problems that require corrective actions.

Moreover, the applicant stated that plant-specific operating experience indicates that the CCW system performance has been very satisfactory. No evidence of corrosion product buildup or corrosion-induced through-wall cracking in CCW piping has ever been identified at Ginna. Confirmation of the effectiveness of the CCW chemistry control was obtained during remote visual inspection of the internal surfaces of the carbon steel heat exchanger shell, tubesheet, and tube supports, as well as piping connections during retubing of both CCW heat exchangers in 1999. All surfaces were clean, free of deposits and corrosion products, and in excellent condition. The applicant also indicated that additional information is provided in the response to RAI B2.1.9-1.

On the basis of its review, the staff finds that the applicant’s response is acceptable because the applicant’s activities as described above will ensure early detection of CCW system problems that require corrective actions, and the plant-specific operating experience shows that the CCW system performance has been satisfactory. The staff considers the issue related to RAI 3.4.1-1 to be resolved.

By letter dated March 21, 2003, the staff issued RAI 3.4-3 pertaining to the use of the Periodic Surveillance Preventive Maintenance Program for internal surfaces of components and the use of the Systems Monitoring Program for external surfaces of the carbon steel components in several of the auxiliary systems in the LRA. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.3 of this SER, and the issue is characterized as resolved.

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs with managing the aging effects for the materials and environments associated with the CVCS.

In addition, the staff reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program and found it to be acceptable, as required by 10 CFR 54.21(d).

3.3.2.4.1.3 Conclusions. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and AMPs credited with managing the aging effects for components in the CVCS, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement provides an adequate program description of the AMPs credited with managing aging in the CVCS to satisfy 10 CFR 54.21(d).

3.3.2.4.2 Component Cooling Water

3.3.2.4.2.1 Summary of Technical Information in the Application. The description of the CCW system can be found in Section 2.3.3.2 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3.3-2. The components, aging effects, and AMPs are provided in LRA Tables 3.4-1 and 3.4-2.

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 2.3.3-2, on pages 2-102, 2-103, and 2-104, of the LRA lists individual components of the system including cooler, containment spray components, fasteners (bolting), flow element, heat exchanger, indicator, orifice, pipe, pump casing, switch, tank, temperature element, transmitter, and valve body.

For the internal environments, the LRA identifies the stainless steel, carbon/low alloy steel, copper alloy, cast iron, and CASS exposed to treated water—other, or stainless steel exposed to treated water—primary less than 140 °F, or treated water—secondary greater than 120 °F as subject to loss of material. Carbon/low-alloy steel and copper alloy exposed to raw water are subject to loss of material aging effects. Stainless steel exposed to treated water—secondary greater than 120 °F is subject to cracking due to SCC. The applicant also identified HX-stainless steel or HX-copper alloy (stainless steel or copper alloy used for heat transfer purpose) in raw water, treated water—other, treated water—primary less than 140 °F, or treated water—secondary greater than 120 °F as subject to loss of heat transfer. No aging effects were identified for stainless steel, carbon/low-alloy steel, or copper alloy (zinc less than 15 percent) exposed to air and gas, or neoprene exposed to treated water—other.

For the external environments in Ginna, the LRA identifies that carbon/low-alloy steel exposed to borated water leaks is subject to loss of material aging effects. Carbon/low-alloy steel in indoor not-air-conditioned environments is subject to loss of material, loss of preload due to stress relaxation, and cracking due to SCC. Neoprene in containment is subject to change in material properties and cracking. The applicant also identified carbon/low-alloy steel in containment or indoor not-air-conditioned environments, or cast iron exposed to indoor not-air-conditioned environments, as subject to loss of material aging effects. No aging effects were identified for stainless steel in concrete, containment, indoor not-air-conditioned environments, or exposed to borated water leaks. No aging effects were identified for CASS or copper alloy (zinc less than 15 percent) in indoor not-air-conditioned environments.

Aging Management Programs

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

- Bolting Integrity Program (B2.1.5)
- Water Chemistry Program (B2.1.37)
- Boric Acid Corrosion Program (B2.1.6)
- Periodic Surveillance and Preventive Maintenance Program (B2.1.23)
- System Monitoring Program (B2.1.33)
- Open-Cycle (Component) Cooling Water System Program (B2.1.22)
- Closed-Cycle (Component) Cooling Water System Program (B2.1.9)

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

3.3.2.4.2.2 Staff Evaluation

Aging Effects

The staff reviewed the information in Tables 2.3.3-2, 3.4-1, and 3.4-2 for the CCW system. During its review, the staff determined that additional information was needed to complete its review.

In LRA Table 2.3.3-2, the AMR results indicate that Table 3.4-1, lines 5 and 14, and Table 3.4-2, lines 120, 130, 132, 133, 151, 152, 153, and 154, are applicable to heat exchangers in the CCW system. The applicant credited the Periodic Surveillance and Preventive Maintenance Program, One-Time Inspection Program, Closed-Cycle (Component) Cooling Water System Program, and

Water Chemistry Control Program with managing loss of material due to various aging mechanisms and cracking due to SCC. However, the GALL Report recommends that the Open-Cycle Cooling Water System Program and the Selective Leaching of Materials AMP be used to detect occurrence of selective leaching for components that are exposed to raw water, treated water, and ground water environments by hardness measurement. By letter dated March 21, 2003, the staff requested, in RAI 3.4.2-1, the applicant to confirm that parameters monitored/inspected as recommended by the GALL Report are adequately covered in the applicant's AMPs identified above.

In its response, dated May 13, 2003, the applicant stated that Table 3.4-1, lines 5 and 14, include the EDG lube oil and jacket water heat exchangers. The tubes in these heat exchangers are arsenical (inhibited) admiralty brass. The presence of arsenic acts to inhibit the selective leaching mechanism (i.e., dezincification) in the admiralty brasses. The tubeside environment in both of these heat exchangers is service (raw) water. The tubes are periodically inspected by eddy current testing under the Periodic Surveillance and Preventive Maintenance Program. The eddy current inspections provide a very effective means of detecting any tube degradation resulting from dezincification. The shell and channel heads of these units are gray cast iron. The shellside environment of the lubricating oil heat exchanger is lubricating oil, which would not support the selective leaching mechanism (graphitic corrosion of gray iron). The shellside environment of the jacket water heat exchanger is chromated water. Potassium dichromate is an effective and reliable corrosion inhibitor and would also suppress the selective leaching mechanism. The concentration of potassium dichromate is controlled and maintained under the Water Chemistry Control Program at Ginna. The applicant also stated that the channel heads are removed and inspected when the tubes are inspected. The channel heads are fitted with sacrificial zinc anodes which are periodically replaced under the Periodic Surveillance and Preventive Maintenance Program. The zinc anodes effectively suppress the selective leaching mechanism. The applicant further stated that a sample of components potentially susceptible to selective leaching in raw water environments will be inspected under the One-Time Inspection Program. The sample will include the EDG jacket water and lube oil heat exchanger channel heads. This inspection will be performed prior to the end of the current license period. The inspection will be conducted using an eddy current technique (pancake probe). The applicant stated that hardness tests may also be used if component configuration and geometry allow as described in response to RAI B2.1.29-1.

The applicant also stated that LRA Table 3.4-2, lines 120, 130, 132, 133, and 151 through 154 identify heat exchangers that are exposed to a variety of environments, including raw and treated water. Line 120 includes carbon steel components which are not susceptible to selective leaching. Lines 130, 132, and 133 refer to admiralty brass tubes which are inspected by eddy current testing under the Periodic Surveillance and Preventive Maintenance Program, and therefore any degradation due to selective leaching (dezincification) would be readily detected. Lines 151, 152, 153, and 154 include stainless steel heat exchanger components which are not susceptible to selective leaching.

On the basis of its review, the staff finds that the applicant's response is acceptable because the applicant has demonstrated that the use of the above AMPs will adequately manage the aging effect of selective leaching for these components. The staff considers the issue related to RAI 3.4.2-1 to be resolved.

By letter dated March 21, 2003, the staff issued RAI 3.4-3 pertaining to the use of the Periodic Surveillance and Preventive Maintenance Program for internal surfaces of components and the use of the System Monitoring Program for external surfaces of the carbon steel components in several of the auxiliary systems in the LRA. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.3 of this SER, and the issue is characterized as resolved.

By letter dated March 21, 2003, the staff issued RAI 3.4-6 pertaining to the aging effects of the neoprene pipes that are exposed to oil and fuel oil, raw water, and treated water—other environments in several of the auxiliary systems in the LRA. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.6 of this SER, and this 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 CCW system SSCs with the environments described in Tables 2.3.3-2, 3.4-1, and 3.4-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the CCW system.

<u>Aging Management Programs</u>

The applicant credited the following AMPs with managing the aging effects in the CCW system:

- Bolting Integrity Program (3.0.3.3)
- Water Chemistry Control Program (3.0.3.1)
- Boric Acid Corrosion Program (3.0.3.4)
- Periodic Surveillance and Preventive Maintenance Program (3.0.3.8)
- System Monitoring Program (3.0.3.11)
- Open-Cycle (Component) Cooling Water System Program (3.3.2.3.6)
- Closed-Cycle (Component) Cooling Water System Program (3.0.3.5)

With the exception of the Open-Cycle (Component) Cooling Water System Program, these AMPs are credited with managing the aging effects of components in several structures and systems and, therefore, are 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 common AMPs is documented in the SER sections given in parentheses above. The Open-Cycle (Component) Cooling Water System Program has been evaluated and found to be appropriate for this system. The staff's evaluation of the Open-Cycle (Component) Cooling Water System Program is documented in Section 3.3.2.3.6 of this SER.

After evaluating the applicant's AMR for each of the components in the CCW system, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects for this system. For those components identified in Table 3.4-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in LRA Table 3.4-2, the staff verified that the applicant credited AMPs that are appropriate for the identified aging effects.

On the basis of its review, the staff finds that the applicant has credited the appropriate AMPs with managing the aging effects for the materials and environments associated with the CCW system. In addition, the staff reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program and found it to be acceptable, as required by 10 CFR 54.21(d).

3.3.2.4.2.3 Conclusions. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and AMPs credited with managing the aging effects for components in the CCW system, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement provides an adequate program description of the AMPs credited with managing aging in the CCW system to satisfy 10 CFR 54.21(d).

3.3.2.4.3 Spent Fuel Cooling and Fuel Storage

3.3.2.4.3.1 Summary of Technical Information in the Application. The description of the spent fuel cooling and fuel storage system can be found in Section 2.3.3.3 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3.3-3. The components, aging effects, and AMPs are provided in LRA Tables 3.4-1 and 3.4-2.

Aging Effects

Components of the SFC&FS 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 2.3.3-3, on pages 2-109 through 2-111, of the LRA lists individual components of the system including containment spray components, demineralizer, diaphragm seal, fasteners (bolting), filter housing, flow element, heat exchanger, indicator, pipe, pulsation damper, pump casing, spectacle flange, strainer housing, structures, tank, temperature element, and valve body.

For the internal environments, the LRA identifies the stainless steel, CASS, and copper alloy (zinc less than 15 percent) exposed to treated water—borated less than 140 °F as subject to loss of material. Neoprene exposed to treated water—borated less than 140 °F is subject to change in material properties and cracking. The applicant also identified stainless steel and carbon/low alloy steel in raw water as subject to loss of material, and stainless steel in raw water and in treated water—borated less than 140 °F as subject to loss of heat transfer. No aging effects were identified for neoprene exposed to air and gas.

For the external environments, the LRA identifies carbon/low-alloy steel exposed to borated water leaks as subject to loss of material aging effects. The LRA also identifies carbon/low-alloy steel in an indoor not-air-conditioned environment as subject to loss of material, loss of preload due to stress relaxation, and cracking due to SCC. The LRA does not identify any aging effects for stainless steel, cast austenitic steel, and copper alloy (zinc less than 15 percent) exposed to indoor not-air-conditioned, or for stainless steel exposed to borated water leaks or buried environments.

Aging Management Programs

The following AMPs are utilized to manage aging effects in the SFC&FS system:

- Bolting Integrity Program (B2.1.5)
- Water Chemistry Control Program (B2.1.37)
- Boric Acid Corrosion Program (B2.1.6)
- Periodic Surveillance and Preventive Maintenance Program (B2.1.23)
- One-Time Inspection Program (B2.1.21)
- System Monitoring Program (B2.1.33)
- Open-Cycle (Component) Cooling Water System Program (B2.1.22)
- Structures Monitoring Program (B2.1.32)
- Spent Fuel Pool Neutron Absorber Monitoring Program (B2.1.30)

A description of these AMPs is provided in Appendix B to the LRA. The applicant concluded that the effects of aging associated with the components of the SFC&FS system will be adequately managed by these AMPs during the period of extended operation.

3.3.2.4.3.2 Staff Evaluation

Aging Effects

The staff reviewed the information in Tables 2.3.3-3, 3.4-1, and 3.4-2 for the SFC&FS system. During its review, the staff determined that additional information was needed to complete its review.

In the LRA, Table 3.4-2, line 430, indicates that, for valve body (copper alloy) in the SFC&FS system, under the indoor not-air-conditioned environment, there is no aging effect. However, the Periodic Surveillance and Preventive Maintenance Program was identified as the AMP. By letter dated March 21, 2003, the staff requested, in RAI 3.4.3-1, the applicant to clarify this apparent inconsistency.

In its response, dated May 13, 2003, the applicant stated that, as denoted in LRA Table 3.4-2, line 430, the subject valves are in the SFC&FS system. The Preventive Maintenance Program was properly applied to the internal environment of treated water—borated (less than 140 °F), but was mistakenly applied to the same valves in the external environment.

On the basis of its review, the staff finds that the applicant's response is acceptable because the applicant clarified that the Preventive Maintenance Program was mistakenly applied to the external environment of the subject valve. The staff considers the issue related to RAI 3.4.3-1 to be resolved.

By letter dated March 21, 2003, the staff issued RAI 3.4-3 pertaining to the use of the Periodic Surveillance and Preventive Maintenance Program for internal surfaces of components and the use of the Systems Monitoring Program for external surfaces of the carbon steel components in several of the auxiliary systems in the LRA. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.3 of this 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 SFC&FS system SSCs with the environments described in Tables 2.3.3-3, 3.4-1, and 3.4-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the SFC&FS system.

<u>Aging Management Programs</u>

The applicant credited the following AMPs with managing the aging effects in the SFC&FS system:

- Bolting Integrity Program (3.0.3.3)
- Water Chemistry Control Program (3.0.3.1)
- Boric Acid Corrosion Program (3.0.3.4)
- Periodic Surveillance and Preventive Maintenance Program (3.0.3.8)
- One-Time Inspection Program (3.0.3.7)
- Systems Monitoring Program (3.0.3.11)
- Open-Cycle (Component) Cooling Water System Program (3.3.2.3.6)
- Structures Monitoring Program (3.0.3.10)
- Spent Fuel Pool Neutron Absorber Monitoring Program (3.3.2.3.7)

With the exception of the Open-Cycle (Component) Cooling Water System Program and the Spent Fuel Pool Neutron Absorber Monitoring Program, these AMPs are credited with managing the aging effects of components in several structures and systems and, therefore, are 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 common AMPs is documented in the SER sections given in parentheses above.
The Open-Cycle (Component) Cooling Water System Program and the Spent Fuel Pool Neutron Absorber Monitoring Program have been evaluated and found to be appropriate for this system. The staff's evaluation of the Open-Cycle (Component) Cooling Water System Program and the Spent Fuel Pool Neutron Absorber Monitoring Program is documented in Sections 3.3.2.3.6 and 3.3.2.3.7 of this SER, respectively.

After evaluating the applicant's AMR for each of the components in the SFC&FS system, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects for this system. For those components identified in Table 3.4-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in LRA Table 3.4-2, the staff verified that the applicant credited AMPs that are appropriate for the identified aging effects.

On the basis of its review, the staff finds that the applicant has credited the appropriate AMPs with managing the aging effects for the materials and environments associated with the SFC&FS system. In addition, the staff reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program and found it to be acceptable, as required by 10 CFR 54.21(d).

3.3.2.4.3.3 Conclusions. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and AMPs credited with managing the aging effects for components in the SFC&FS system, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement provides an adequate program description of the AMPs credited with managing aging in the SFC&FS system to satisfy 10 CFR 54.21(d).

3.3.2.4.4 Waste Disposal System

3.3.2.4.4.1 Summary of Technical Information in the Application. The description of the waste disposal system can be found in Section 2.3.3.4 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3.3-4. The components, aging effects, and AMPs are provided in LRA Tables 3.4-1 and 3.4-2.

Aging Effects

Components of the waste disposal system are described in Section 2.3.3.4 of the submittal as being within the scope of license renewal and subject to an AMR. Table 2.3.3-4 of the LRA lists individual components of the system including bolting, heat exchanger, orifice, pipes and fittings, pump casings, tanks, and valve bodies. Fasteners bolting and external surfaces of carbon steel and low-alloy steel components are identified as being subject to loss of material due to boric acid corrosion from exposure to borated water spillage.

The LRA identifies that carbon steel, galvanized steel, and copper in air are subject to loss of material due to general external corrosion, and carbon steel and low-alloy steel in dripping boric acid are subject to loss of material due to boric acid corrosion. The LRA also identifies that stainless steel in borated treated water was subject to cracking due to SCC. The LRA does not identify any aging effects for aluminum and stainless steel in air or concrete, or for carbon steel or cast iron in concrete.

Aging Management Programs

The following AMPs are utilized to manage aging effects for the waste disposal system:

- Closed-Cycle (Component) Cooling Water System Program (B.2.1.9)
- One-Time Inspection Program (B2.1.21)
- Periodic Surveillance and Preventive Maintenance Program (B2.1.23)

- Water Chemistry Program (B2.1.37)
- Boric Acid Corrosion Program (B2.1.6)
- Bolting Integrity Program (B2.1.5)
- Systems Monitoring Program (B2.1.33)

The applicant concluded that the effects of aging associated with the components of the waste disposal system will be adequately managed by these AMPs during the period of extended operation.

3.3.2.4.4.2 Staff Evaluation

Aging Effects

The staff reviewed the information in Tables 2.3.3-4, 3.4-1, and 3.4-2 for the waste disposal system. During its review, the staff determined that additional information was needed to complete its review.

In LRA Table 3.4.-1, line 14, and Table 3.4-2, line 132, the applicant credited the Closed-Cycle (Component) Cooling Water System Program with managing the aging effect of loss of material due to general, pitting, and crevice corrosion, as well as MIC for heat exchangers in the waste disposal system. However, the staff noted that the program description in LRA Appendix B2.19 for the Closed-Cycle (Component) Cooling Water System Program does not include the waste disposal system. By letter dated March 21, 2003, the staff requested, in RAI 3.3.4-1, the applicant to clarify this discrepancy between Table 2.3.3-4 and Appendix B2.1.9. In its response, dated May 13, 2003, the applicant stated that the scope of the Closed-Cycle (Component) Cooling Water System Program includes all components exposed to component cooling water and therefore includes components in the waste disposal system serviced by the CCW system. The staff's evaluation of the applicant's response is documented in Section 3.0.3.5 of this 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 RAI, the staff finds that the aging effects that result from contact of the waste disposal system SSCs with the environments described in Tables 2.3.3-4, 3.4-1, and 3.4-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the waste disposal system.

Aging Management Programs

The applicant credited the following AMPs with managing the aging effects in the waste disposal system:

- Closed-Cycle (Component) Cooling Water System Program (3.0.3.5)
- One-Time Inspection Program (3.0.3.7)
- Periodic Surveillance and Preventive Maintenance Program (3.0.3.8)

- Water Chemistry Program (3.0.3.1)
- Boric Acid Corrosion Program (3.0.3.4)
- Bolting Integrity Program (3.0.3.3)
- Systems Monitoring Program (3.0.3.11)

These AMPs are credited with managing the aging effects of components in several structures and systems and, therefore, are 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 common AMPs is documented in the sections of this SER listed in parentheses above. The Closed-Cycle (Component) Cooling Water System Program has been evaluated and found to be appropriate for this system.

After evaluating the applicant's AMR for each of the components in the waste disposal system, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects for this system. For those components identified in Table 3.4-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in LRA Table 3.4-2, the staff verified that the applicant credited AMPs that are appropriate for the identified aging effects.

On the basis of its review, the staff finds that the applicant has credited the appropriate AMPs with managing the aging effects for the materials and environments associated with the waste disposal system. In addition, the staff reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program and found it to be acceptable, as required by 10 CFR 54.21(d).

3.3.2.4.4.3 Conclusions. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and AMPs credited with managing the aging effects for components in the waste disposal system, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement provides an adequate program description of the AMPs credited with managing aging in the waste disposal system to satisfy 10 CFR 54.21(d).

3.3.2.4.5 Service Water System

3.3.2.4.5.1 Summary of Technical Information in the Application. The description of the service water system can be found in Section 2.3.3.5 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3.3-5. The components, aging effects, and AMPs are provided in LRA Tables 3.4-1 and 3.4-2.

Aging Effects

Components of the service water system are described in Section 2.3.3.5 of the submittal as being within the scope of license renewal and subject to an AMR. Table 2.3.3-5 of the LRA lists individual components of the system including expansion joint, fasteners (bolting), flow elements, indicator, pipe, pump casing, strainer housing, structure, switch, temperature element, and valve body. Fasteners bolting and external surfaces of carbon steel and low-alloy steel components are identified as being subject to loss of material due to boric acid corrosion from exposure to borated water leaking from an adjacent system or component containing borated treated water. The applicant identified stainless steel, carbon steel, cast steel, cast iron, and copper alloy components exposed to raw water as being subject to loss of material due to general, pitting, crevice, and galvanic corrosion, MIC, and biofouling.

The LRA identifies that carbon steel, low-alloy steel, and cast iron in air are subject to loss of material due to general external corrosion, and carbon steel and low-alloy steel in dripping boric acid are subject to loss of material due to boric acid corrosion. The LRA also identifies that stainless steel in oil and fuel oil and buried cast iron are subject to loss of material.
The applicant identified neoprene in the containment or indoor not-air-conditioned environment as being subject to change in material properties and cracking aging effects. The applicant also identified carbon/low-alloy steel in containment or indoor not-air-conditioned environments and cast iron exposed to indoor not-air-conditioned environments as subject to loss of material aging effects. The LRA does not identify any aging effects for stainless steel in concrete, containment, indoor not-air-conditioned environments, or exposed to borated water leaks. No aging effects were identified for buried concrete or for CASS or copper alloy (zinc less than 15 percent) in indoor not-air-conditioned environments, or for neoprene in raw water environment.

<u>Aging Management Programs</u>

The LRA credited the following AMPs with managing the identified aging effects for the service water system:

- Open-Cycle Cooling (Service) Water Program (B2.1.22)
- Boric Acid Corrosion Program (B2.1.6)
- Systems Monitoring Program (B2.1.33)
- Bolting Integrity Program (B2.1.5)
- Fire Water System Program (B2.1.14)
- One-Time Inspection Program (B2.1.21)
- Periodic Surveillance and Preventive Maintenance Program (B2.1.23)

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

3.3.2.4.5.2 <u>Staff Evaluation</u>

<u>Aging Effects</u>

The staff reviewed the information in Tables 2.3-5, 3.4-1, and 3.4-2 for the service water system. During its review, the staff determined that additional information was needed to complete its review.

By letter dated March 21, 2003, the staff issued RAI 3.3-4 pertaining to the aging effect/mechanism for copper alloy components in the service water systems that are exposed to indoor not-air-conditioned environment. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.7 of this SER, and the issue is characterized as resolved.

By letter dated March 21, 2003, the staff issued RAI 3.4-6 pertaining to the aging effects of the neoprene pipes that are exposed to oil and fuel oil, raw water, and treated water—other environments in several of the auxiliary systems in the LRA. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.6 of this SER, and this 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 service water system SSCs with the environments described in Tables 2.3.3-5, 3.4-1, and 3.4-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the service water system.

<u>Aging Management Programs</u>

The applicant has credited the following AMPs with managing the aging effects in the service water system:

- Open-Cycle Cooling (Service) Water Program (3.3.2.3.6)
- Boric Acid Corrosion Program (3.0.3.4)
- Systems Monitoring Program (3.0.3.11)
- Bolting Integrity Program (3.0.3.3)
- Fire Water System Program (3.3.2.3.3)
- One-Time Inspection Program (3.0.3.7)
- Periodic Surveillance and Preventive Maintenance Program (3.0.3.8)

With the exception of the Open-Cycle Cooling (Service) Water Program and the Fire Water System Program, these AMPs are credited with managing the aging effects of components in several structures and systems and, therefore, are 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 common AMPs is documented in the sections of this SER given in parentheses above. The Open-Cycle Cooling (Service) Water Program and the Fire Water System Program have been evaluated and found to be appropriate for this system. The staff's evaluation of the Open-Cycle Cooling (Service) Water Program and the Fire Water System Program is documented in Sections 3.3.2.3.6 and 3.3.2.3.3 of this SER, respectively.

After evaluating the applicant's AMR for each of the components in the service water system, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects for this system. For those components identified in Table 3.4-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report.

For the components identified in LRA Table 3.4-2, the staff verified that the applicant credited AMPs that are appropriate for the identified aging effects.

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs with managing the aging effects for the materials and environments associated with the service water system. In addition, the staff reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program and found it to be acceptable, as required by 10 CFR 54.21(d).

3.3.2.4.5.3 Conclusions. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and AMPs credited with managing the aging effects for components in the service water system, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement provides an adequate program description of the AMPs credited with managing aging in the service water system to satisfy 10 CFR 54.21(d).

3.3.2.4.6 Fire Protection System

3.3.2.4.6.1 Summary of Technical Information in the Application. The description of the FP system can be found in Section 2.3.3.6 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3.3-6. The components, aging effects, and AMPs are provided in LRA Tables 3.4-1 and 3.4-2.

Aging Effects

Table 2.3.3-6 of the LRA lists individual components that are within the scope of license renewal and subject to an AMR. The components include bolting, pump casings, gas cylinders, nozzles, coolers, fittings, sprinklers, valves, piping, tubings, and filter housings. Table 2.3.3-6 also addresses fire barriers.

The LRA, in Section 3.4, identifies that aluminum, stainless steel, carbon steel, cast iron, concrete, copper, and flame-retardant coatings are subject to loss of material due to general exterior corrosion, and carbon steel, low-alloy steel, and aluminum are subject to loss of material due to boric acid corrosion. Buried piping is subject to loss of material due to general, pitting, and crevice corrosion, and MIC. Doors, fire barrier penetration seals, and concrete are subject to a loss of material due to wear, hardening, and shrinkage due to weathering. Carbon steel and aluminum are subject to a loss of material due to general, pitting, crevice, and galvanic corrosion, MIC, and biofouling. Aluminum, bronze, brass, cast iron, and cast steel are subject to loss of material due to selective leaching.

The LRA, in Table 3.4-2, identifies no aging effects for carbon steel in areas protected from the weather, not subject to condensation, and not subjected to aggressive chemical attack. Table 3.4.2 also identifies no aging effects for copper alloys, SS, and glass in air.

Aging Management Programs

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

- Fire Protection Program (B2.1.13)
- Boric Acid Corrosion Program (B2.1.6)
- Fire Water System Program (B2.1.14)
- Structures Monitoring Program (B2.1.32)
- Periodic Surveillance and Preventive Maintenance Program (B2.1.23)
- One-Time Inspection Program (B2.1.21)
- Fuel Oil Chemistry Program (B2.1.16)
- Systems Monitoring Program (B2.1.33)
- Bolting Integrity Program (B2.1.5)

A description of these AMPs is provided in Appendix B to the LRA.

3.3.2.4.6.2 Staff Evaluation. The staff reviewed the information in LRA Tables 2.3.3.6, 3.4-1, and 3.4-2 for the FP system. During its review, the staff requested additional information in order to complete its review of the Fire Protection Program.

In RAIs 2.3.3.6-1, 2.3.3.6-3, and 2.3.3.6-4, the staff requested information concerning various portions of the FP system that were not included within the scope of license renewal.
In RAI 2.3.3.6-2, the staff requested additional information concerning the AMP for underground fire water piping. The staff's evaluation of the scope of the FP system is in Section 2.3.3.6 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 RAIs, the staff finds that the aging effects identified for the FP SCs described in LRA Tables 2.3.3-6, 3.4-1, and 3.4-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the material and environments associated with the components in the FP system.

Aging Management Programs

The applicant credited the following AMPs with managing the aging effects in the FP system:

- Fire Protection Program (3.3.2.3.2)
- Boric Acid Corrosion Program (3.0.3.4)
- Fire Water System Program (3.3.2.3.3)
- Structures Monitoring Program (3.0.3.10)
- Periodic Surveillance and Preventive Maintenance Program (3.0.3.8)
- One-Time Inspection Program (3.0.3.7)
- Fuel Oil Chemistry Program (3.3.2.3.4)
- Systems Monitoring Program (3.0.3.11)
- Bolting Integrity Program (3.0.3.3)

These AMPs are credited with managing the aging effects of components in several structures and systems and, therefore, are 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. These AMPs are evaluated in sections as indicated above in this SER.

On the basis of its review of the information provided in the LRA, the staff concludes that the above identified AMPs will effectively manage the aging effects of the Fire Protection Program.

On the basis of its review, the staff finds that the applicant has credited the appropriate AMPs with managing the aging effects from the materials and environments associated with the FP system.

3.3.2.4.6.3 Conclusions. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and AMPs credited with managing the aging effects for components in the FP system, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(d).

3.3.2.4.7 Heating Steam System

3.3.2.4.7.1 Summary of Technical Information in the Application. The description of the heating steam system can be found in Section 2.3.3.7 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3.3-7. The components, aging effects, and AMPs are provided in LRA Tables 3.4-1 and 3.4-2.

Aging Effects

Components of the heating steam 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 2.3.3-7, on page 2-136 of the LRA, and the applicant's letter dated June 10, 2003, Attachment 2, list individual components of the system including heater, pipe, strainer housing, trap housing, valve body, and boiler package.

For the internal environments, the LRA identifies copper alloy (zinc less than 15 percent) and carbon/low-alloy steel exposed to treated water—secondary greater than 120 °F as subject to the loss of material aging effect. No aging effects were identified for copper alloy (zinc less than 15 percent) and carbon/low-alloy steel exposed to air and gas.

For the external environments, the LRA identifies carbon/low-alloy steel exposed to an indoor not-air-conditioned environment as subject to loss of material aging effect. The LRA does not identify any aging effects for copper alloy (zinc less than 15 percent) exposed to an indoor not-air-conditioned environment.

Aging Management Programs

The following AMPs are utilized to manage aging effects in the heating steam system:

- Water Chemistry Control Program (B2.1.37)
- Periodic Surveillance and Preventive Maintenance Program (B2.1.23)
- Systems Monitoring Program (B2.1.33)

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

3.3.2.4.7.2 Staff Evaluation

Aging Effects

The staff reviewed the information in Tables 2.3.3-7, 3.4-1, and 3.4-2 for the heating steam system. During its review, the staff determined that additional information was needed to complete its review.

LRA Table 3.4-2, line 430, indicates that, for valve body (copper alloy) in the SFC&FS system and the heating steam system, exposed to an indoor not-air-conditioned environment, there is no aging effect. However, the Periodic Surveillance and Preventive Maintenance Program was identified as the AMP. By letter dated March 21, 2003, the staff requested, in RAI 3.4.3-1, the applicant to clarify this apparent inconsistency.

In its response, dated May 13, 2003, the applicant stated that, as denoted in LRA Table 3.4-2, line 430, the subject valves are in the SFC&FS system and the heating steam system. The Preventive Maintenance Program was properly applied to the internal environment of treated water—borated less than 140 °F, but was mistakenly applied to the same valves in the external environment.

On the basis of its review, the staff finds that the applicant's response is acceptable because the applicant clarified that the Preventive Maintenance Program was properly applied to the internal environment of treated water—borated less than 140 °F but was mistakenly applied to the same valves in the external environment. The staff considers the issue related to RAI 3.4.3-1 to be resolved.

As a result of the scoping and screening and AMRs associated with RAI 2.1-4, in its response supplementary information dated June 10 and July 11, 2003, the applicant had added the boiler package, pipe, and valve body to the heating steam system component group in Table 2.3.3-7. The staff has reviewed the aging effects and aging management for those components and found them to be acceptable.

By letter dated March 21, 2003, the staff issued RAI 3.4-3 pertaining to the use of the Periodic Surveillance and Preventive Maintenance Program for internal surfaces of components and the use of the System Monitoring Program for external surfaces of the carbon steel components in several of the auxiliary systems in the LRA. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.3 of this 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 heating steam system SSCs with the environments described in Tables 2.3.3-7, 3.4-1, and 3.4-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the heating steam system.

Aging Management Programs

The applicant credited the following AMPs for managing the aging effects in the heating steam system:

- Water Chemistry Control Program (3.0.3.1)
- Periodic Surveillance and Preventive Maintenance Program (3.0.3.8)
- Systems Monitoring Program (3.0.3.11)

These AMPs are credited with managing the aging effects of components in several structures and systems and, therefore, are 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 common AMPs is documented in the sections of the SER given in parentheses above.

After evaluating the applicant's AMR for each of the components in the heating steam system, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects for this system. For those components identified in Table 3.4-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in LRA Table 3.4-2, the staff verified that the applicant credited AMPs that are appropriate for the identified aging effects.

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs with managing the aging effects for the materials and environments associated with the heating steam system. In addition, the staff reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program and found it to be acceptable, as required by 10 CFR 54.21(d).

3.3.2.4.7.3 Conclusions. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and AMPs credited with managing the aging effects for components in the heating steam system, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement provides an adequate program description of the AMPs credited with managing aging in the heating steam system to satisfy 10 CFR 54.21(d).

3.3.2.4.8 Emergency Power System

3.3.2.4.8.1 Summary of Technical Information in the Application. The description of the emergency power system can be found in Section 2.3.3.8 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3.3-8. The components, aging effects, and AMPs are provided in LRA Tables 3.4-1 and 3.4-2.

Aging Effects

Components of the emergency power 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 2.3.3-8, on pages 2-139 through 2-142 of the LRA, lists individual components of the system including accumulator, cooler, engine casing, expansion joint, fan casing, fasteners (bolting), filter housing, governer, heat exchanger, heating element, indicator, level glass, lubricator, muffler, orifice, pipe, pump casing, strainer housing, tank, temperature elements, and valve body.

For the internal environments, the LRA identifies carbon/low-alloy steel, cast iron, aluminum, stainless steel, and copper alloy (zinc less than 15 percent) exposed to oil and fuel oil as subject to loss of material aging effects. Carbon/low-alloy steel, stainless steel, cast iron, and copper alloy exposed to air and gas (wetted) less than 140 °F are subject to loss of material aging effects. Cast iron and copper alloy (zinc greater than 15 percent) in raw water are subject to loss of material aging effects. Copper alloy, cast iron, stainless steel, and carbon/low-alloy steel exposed to treated water—other are subject to loss of material aging effects. The LRA also identifies copper alloy (zinc greater than 15 percent) exposed to air and gas (wetted) greater than 140 °F, raw water, and treated water—other as subject to loss of heat transfer. No aging effects were identified for galvanized carbon steel in air and gas (wetted) greater than 140 °F, aluminum in air and gas, stainless steel in air and gas (wetted) less than 140 °F, glass in oil and fuel oil, and neoprene exposed to air and gas, oil and fuel oil, and treated water—other environments.

For the external environments at Ginna, the LRA identifies carbon/low-alloy steel and cast iron exposed to indoor not-air-conditioned environments as subject to loss of material aging effects. Carbon/low-alloy steel in buried environments is subject to loss of material. The LRA also identifies carbon/low-alloy steel in indoor not-air-conditioned environments as subject to loss of preload due to stress relaxation and cracking due to SCC. Neoprene exposed to indoor not-air-conditioned environments is subject to change in material properties and cracking. No aging effects were identified for galvanized carbon steel, stainless steel, aluminum, copper alloy (zinc less than 15 percent) and glass exposed to indoor not-air-conditioned environments. Stainless steel in buried environments shows no aging effects.

Aging Management Programs

The following AMPs are utilized to manage aging effects in the emergency power system:

- Bolting Integrity Program (B2.1.5)

- Periodic Surveillance and Preventive Maintenance Program (B2.1.23)
- One-Time Inspection Program (B2.1.21)
- Systems Monitoring Program (B2.1.33)
- Open-Cycle Cooling (Service) Water System Program (B2.1.22)
- Fuel Oil Chemistry Program (B2.1.16)

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

3.3.2.4.8.2 Staff Evaluation

Aging Effects

The staff reviewed the information in Tables 2.3.3-8, 3.4-1, and 3.4-2 for the emergency power system. During its review, the staff determined that additional information was needed to complete its review.

In LRA Table 3.4-1, line 16, the applicant credited the Open-Cycle Cooling (Service) Water System Program with managing the aging effects of loss of material due to general, pitting, crevice, and galvanic corrosion, MIC, and biofouling for the components within the emergency power system. However, in Table 2.3.3-8, under aging management reference, line 16 is not listed as a link to the AMR for any components (including heat exchanger) included in the emergency power system. By letter dated March 21, 2003, the staff requested, in RAI 3.4.8-1, the applicant to explain the above discrepancy.

In its response, dated May 23, 2003, the applicant clarified that the line 16 in Table 3.4-1 should be included as an aging management reference in Table 2.3.3-8 for the component group heat exchanger for both the pressure boundary and heat transfer functions.

On the basis of its review, the staff finds that the applicant's response is acceptable because the applicant clarified that line 16 in Table 3.4-1 should be included as an aging management reference for the heat exchanger in Table 2.3.3-8. The staff considers the issue related to RAI 3.4.8-1 to be resolved.

In the LRA, Table 3.4-1, line 17, states that for buried piping and fittings, the Buried Piping and Tank Inspection Program is implemented by the Periodic Surveillance and Preventive Maintenance Program and that tanks in the emergency power system are periodically inspected for signs of applicable aging effects. However, in Table 2.3.3-8, under aging management, line 17 is not listed as a link to the AMR for pipes or tanks covered in the emergency power system. By letter dated March 21, 2003, the staff requested, in RAI 3.4.8-2, the applicant to explain the above discrepancy and to discuss how potential aging effects due to corrosion at tank bottom will be managed.

In its response to RAI 3.4.8-2, dated May 23, 2003, and its clarifications to C-RAI 3.4.8-2, dated July 11, 2003, the applicant clarified that line 17 in Table 3.4-1 should be included as an aging

management reference in Table 2.3.3-8 for the component groups “tank” and “pipe.”
The applicant stated that the responses to RAIs B2.1.7-1, B2.1.8-1, and B2.1.21-3 provide a discussion related to the management of potential aging effects due to corrosion at the tank bottoms.

On the basis of its review, the staff finds that the applicant’s response is acceptable because the applicant clarified that line 17 in Table 3.4-1 should be included as an aging management reference for the tank and pipe in Table 2.3.3-8. The staff considers the issue related to RAI 3.4.8-2 to be resolved.

By letter dated March 21, 2003, the staff issued RAI 3.4-3 pertaining to the use of the Periodic Surveillance and Preventive Maintenance Program for internal surfaces of components and the use of the Systems Monitoring Program for external surfaces of the carbon steel components in several of the auxiliary systems in the LRA. The staff’s evaluation of the applicant’s response is documented in Section 3.3.2.5.3 of this SER, and the issue is characterized as resolved.

By letter dated March 21, 2003, the staff issued RAI 3.4-4 pertaining to the aging effects for numerous galvanized components that are exposed to various environments in several of the auxiliary systems in the LRA. The staff’s evaluation of the applicant’s response is documented in Section 3.3.2.5.4 of this SER, and the issue is characterized as resolved.

By letter dated March 21, 2003, the staff issued RAI 3.4-6 pertaining to the aging effects of the neoprene pipes that are exposed to oil and fuel oil, raw water, and treated water—other environments in several of the auxiliary systems in the LRA. The staff’s evaluation of the applicant’s response is documented in Section 3.3.2.5.6 of this 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 emergency power system SSCs with the environments described in Tables 2.3.3-8, 3.4-1, and 3.4-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the emergency power system.

Aging Management Programs

The applicant credited the following AMPs with managing the aging effects in the emergency power system:

- Bolting Integrity Program (3.0.3.3)
- Periodic Surveillance and Preventive Maintenance Program (3.0.3.8)
- One-Time Inspection Program (3.0.3.7)
- Systems Monitoring Program (3.0.3.11)
- Open-Cycle Cooling (Service) Water System Program (3.3.2.3.6)
- Fuel Oil Chemistry Program (3.3.2.3.4)

With the exception of the Fuel Oil Chemistry Program and the Open-Cycle Cooling (Service) Water System Program, these AMPs are credited with managing the aging effects of components in several structures and systems and, therefore, are 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 common AMPs is documented in sections of this SER given in parentheses above. The Open-Cycle Cooling (Service) Water System Program and the Fuel Oil Chemistry Program have been evaluated and found to be appropriate for this system. The staff's evaluation of the Fuel Oil Chemistry Program and the Open-Cycle Cooling (Service) Water System Program is documented in Sections 3.3.2.3.4 and 3.3.2.3.6 of this SER, respectively.

After evaluating the applicant's AMR for each of the components in the emergency power system, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects for this system. For those components identified in Table 3.4-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in LRA Table 3.4-2, the staff verified that the applicant credited AMPs that are appropriate for the identified aging effects.

On the basis of its review, the staff finds that the applicant has credited the appropriate AMPs with managing the aging effects for the materials and environments associated with the emergency power system. In addition, the staff reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program and found it to be acceptable, as required by 10 CFR 54.21(d).

3.3.2.4.8.3 Conclusions. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and AMPs credited with managing the aging effects for components in the emergency power system, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement provides an adequate program description of the AMPs credited for managing aging in the emergency power system to satisfy 10 CFR 54.21(d).

3.3.2.4.9 Containment Ventilation System

3.3.2.4.9.1 Summary of Technical Information in the Application. The description of the containment ventilation system can be found in Section 2.3.3.9 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3.3-9. The components, aging effects, and AMPs are provided in LRA Tables 3.4-1 and 3.4-2.

Aging Effects

Components of the containment ventilation 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 2.3.3-9, on pages 2-148 through 2-150 of the LRA, lists individual components of the system including air-operated damper housing, cooling coil, carbon steels components, damper housing/frame, expansion joint, fan casing, fasteners (bolting), filter housing, flange, heat exchanger, heating, ventilation, and air conditioning (HVAC) equipment package, pipe, valve body, and ventilation ductwork.

For the internal environments, the LRA identifies carbon/low-alloy steel, cast iron, and copper alloy (zinc less than 15 percent) exposed to air and gas (wetted) less than 140 °F as subject to loss of material aging effect. Copper alloy (zinc less than 15 percent) and stainless steel exposed to raw water are subject to loss of material aging effect. The LRA also identifies HX-copper alloy (zinc less than 15 percent) and HX-stainless steel exposed to air and gas (wetted) less than 140 °F or raw water as subject to loss of heat transfer. Neoprene exposed to air and gas (wetted) less than 140 °F is subject to change in material properties due to elevated temperature. No aging effects were identified for galvanized carbon steel, stainless steel, flexible asbestos cloth, fiberglass-reinforced plastic (FRP), and CASS exposed to air and gas (wetted) less than 140 °F. Nor were any aging effects identified for carbon/low-alloy steel, copper alloy (zinc less than 15 percent), and stainless steel exposed to air and gas.

For the external environments, the LRA identifies carbon/low-alloy steel and cast iron exposed to containment, indoor not-air-conditioned, or outdoor environments as subject to loss of material aging effect. Carbon/low-alloy steel exposed to borated water leaks is subject to loss of material aging effect. The LRA also identifies rubber-coated asbestos exposed to the containment environment and neoprene exposed to indoor not-air-conditioned or outdoor environments as subject to change in material properties and cracking. Carbon/low-alloy steel exposed to an indoor not-air-conditioned environment is subject to loss of preload due to stress relaxation. The LRA does not identify any aging effects for galvanized carbon steel, copper alloy (zinc less than 15 percent), stainless steel, flexible asbestos cloth, and FRP exposed to containment environments. Also, no aging effects were identified for galvanized carbon steel, copper alloy (zinc less than 15 percent), stainless steel, and cast austenitic steel exposed to indoor not-air-conditioned environments. Stainless steel exposed to borated water leaks shows no aging effects.

Aging Management Programs

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

- Bolting Integrity Program (B2.1.5)
- Boric Acid Corrosion Program (B2.1.6)
- Periodic Surveillance and Preventive Maintenance Program (B2.1.23)
- One-Time Inspection Program (B2.1.21)
- Systems Monitoring Program (B2.1.33)
- Open-Cycle (Component) Cooling Water System Program (B2.1.22)

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

3.3.2.4.9.2 Staff Evaluation

Aging Effects

The staff reviewed the information in Tables 2.3.3-9, 3.4-1, and 3.4-2 for the containment ventilation system. During its review, the staff determined that additional information was needed to complete its review.

In the LRA, Table 3.4-2, line 1, identifies loss of material as an aging effect for cast iron air-operated damper housings that are exposed to air and gas (wetted) less than 140 °F and credits the One-Time Inspection Program with managing the aging effect. However, the staff noted that the scope of the One-Time Inspection Program as described on pages B-38 and B-39 of the LRA does not include components that are exposed to air and gas. By letter dated March 21, 2003, the staff requested, in RAI 3.4.9-1, the applicant to (1) clarify this discrepancy, (2) provide a technical basis to justify why the one-time inspection alone is adequate to manage the aging effect, including a discussion of the plant-specific operating experience related to the component of concern to support its conclusion, and (3) address the staff's concerns about the HVAC equipment package (Table 3.4-2, line 162), and valve body (Table 3.4-2, lines 386, 413, and 426).

In its response, dated May 13, 2003, the applicant clarified that the scope of the One-Time Inspection Program description now includes components exposed to air and gas (wetted) less than 140 °F environments.

The applicant also stated that copper alloys and gray cast irons exhibit excellent resistance to atmospheric environments, including moist air. For a discussion of the atmospheric resistance of copper alloys, the applicant referred to the response to RAI 3.3-4. Gray cast irons are considerably more resistant to atmospheric corrosion and corrosion by natural waters than carbon and low-alloy steels. This is primarily a consequence of the elevated silicon content (typically on the order of 2–2.5 percent) in gray irons. A very dramatic example of this resistance was observed when the gray cast iron end bells on the circulating water pumps were removed and inspected in 1996. The end bells, which had been immersed in fresh, raw Lake Ontario water in the screen house bay for 26 years, were found to be in excellent condition.
This inspection was documented photographically. Therefore, the applicant concluded that, since it would be expected that gray cast irons and copper alloys should display very good resistance to moist air and gas environments at temperatures less than 140 °F, a one-time inspection of the components identified in Table 3.4-2, lines 1, 413, and 426 should be sufficient to confirm the absence of potential aging effects, or to verify that age-related degradation is proceeding so slowly as to be negligible.

The applicant further clarified that line 386 refers to carbon or low-alloy steel components that are exposed to an internal "air and gas" environment that is moisture free. Therefore, no aging effects would be expected from exposure of carbon or low-alloy steel to this environment.
In addition, the applicant stated that line 162 (HVAC equipment package) refers to the carbon steel containment recirculation fan cooler housing. The temperature of the housing would be expected to be the same as that of the ambient containment air on either side. Consequently, no condensation would be expected to occur on the housing. Therefore, aging effects, if any, from exposure of carbon steel to this environment would be expected to occur very slowly.

On the basis of its review, the staff finds that the applicant's response is acceptable because the applicant has included the components that are exposed to air and gas in the scope of the One-Time Inspection Program and the applicant has provided adequate justifications and pertinent operating experience to support its conclusion that the one-time inspection alone is adequate to manage the aging effects for cast iron air-operated damper housing, the HVAC equipment package, and valve body. The staff considers the issue related to RAI 3.4.9-1 to be resolved.

In the LRA, Table 3.4-2, line 34, identifies loss of material as the aging effect for copper alloy (zinc less than 15 percent) cooling coil that is exposed to air and gas (wetted) less than 140 °F and credits the One-Time Inspection Program with managing the aging effect. However, the staff noted that the scope of the One-Time Inspection Program, as described on pages B-38 and B-39 of the LRA does not include components that are exposed to air and gas. By letter dated March 21, 2003, the staff requested, in RAI 3.4.9-2, the applicant to clarify this discrepancy.

In its response, dated May 13, 2003, the applicant stated that, as indicated in the response to RAI 3.4.9-1, the scope of the One-Time Inspection Program description now includes components exposed to air and gas (wetted) less than 140 °F environments. The applicant further stated that the justification for including copper alloys exposed to air and gas (wetted) less than 140 °F environments in the scope of the One-Time Inspection Program is also provided in the response to RAI 3.4.9-1.

On the basis of its review, the staff finds that the applicant's response is acceptable because the applicant has clarified that the components exposed to air and gas (wetted) less than 140 °F environments are now included in the scope of the One-Time Inspection Program. The staff considers the issue related to RAI 3.4.9-2 to be resolved.

By letter dated March 21, 2003, the staff issued RAI 3.4-1(a) pertaining to the aging effects of the neoprene (elastomer) components in the containment ventilation system and essential ventilation system, and RAI 3.4-1(b) pertaining to the use of the Periodic Surveillance Preventive Maintenance Program for the neoprene components. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.1 of this SER, and the issue is characterized as resolved.

By letter dated March 21, 2003, the staff issued RAI 3.4-2 pertaining to the use of the One-Time Inspection Program for managing the aging effects of components in the containment ventilation system and essential ventilation system that are included in Table 3.4-1, line 5. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.2 of this SER, and the issue is characterized as resolved.

By letter dated March 21, 2003, the staff issued RAI 3.4-3 pertaining to the use of the Periodic Surveillance and Preventive Maintenance Program for internal surfaces of components, and the use of the System Monitoring Program for external surfaces of the carbon steel components in several of the auxiliary systems in the LRA. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.3 of this SER, and the issue is characterized as resolved.

By letter dated March 21, 2003, the staff issued RAI 3.4-4 pertaining to the aging effects for numerous galvanized carbon steel components that are exposed to various environments in several of the auxiliary systems in the LRA. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.4 of this SER, and the issue is characterized as resolved.

By letter dated March 21, 2003, the staff issued RAI 3.4-5 pertaining to the aging effects of cracking due to SCC for carbon/low-alloy steel fasteners (bolting) in several of the auxiliary systems in the LRA. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.5 of this 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 containment ventilation system SSCs with the environments described in Tables 2.3.3-9, 3.4-1, and 3.4-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the containment ventilation system.

<u>Aging Management Programs</u>

The applicant credited the following AMPs with managing the aging effects in the containment ventilation system:

- Bolting Integrity Program (3.0.3.3)
- Boric Acid Corrosion Program (3.0.3.4)
- Periodic Surveillance and Preventive Maintenance Program (3.0.3.8)
- One-Time Inspection Program (3.0.3.7)
- Systems Monitoring Program (3.0.3.11)
- Open-Cycle (Component) Cooling Water System Program (3.3.2.3.6)

With the exception of the Open-Cycle (Component) Cooling Water System Program, these AMPs are credited with managing the aging effects of components in several structures and systems and, therefore, are 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 common AMPs is documented in the sections of this SER given in parentheses above. The Open-Cycle (Component) Cooling Water System Program has been evaluated and found to be appropriate for this system. The staff's evaluation of the Open-Cycle (Component) Cooling Water System Program is documented in Section 3.3.2.3.6 of this SER.

After evaluating the applicant's AMR for each of the components in the containment ventilation system, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects for this system. For those components identified in Table 3.4-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in LRA Table 3.4-2, the staff verified that the applicant credited AMPs that are appropriate for the identified aging effects.

On the basis of its review, the staff finds that the applicant has credited the appropriate AMPs with managing the aging effects for the materials and environments associated with the containment ventilation system. In addition, the staff reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program and found it to be acceptable, as required by 10 CFR 54.21(d).

3.3.2.4.9.3 Conclusions. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and AMPs credited with managing the aging effects for components in the containment ventilation system, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement provides an adequate program description of the AMPs credited with managing aging in the containment ventilation system to satisfy 10 CFR 54.21(d).

3.3.2.4.10 Essential Ventilation

3.3.2.4.10.1 Summary of Technical Information in the Application. The description of the essential ventilation system can be found in Section 2.3.3.10 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3.3-10. The components, aging effects, and AMPs are provided in LRA Tables 3.4-1 and 3.4-2.

Aging Effects

Components of the essential ventilation 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 2.3.3-10, on pages 2-157 through 2-159 of the LRA, lists individual components of the system including damper housing/frame, expansion joint, fan casing, fasteners (bolting), filter housing, heat exchanger, heating coil, HVAC equipment package, motor-operated damper, and ventilation ductwork.

The applicant identified the component types subject to aging effects review based on the materials exposed to either the internal environments or the external environments (see the definitions of the environments in Tables 3.1-1 and 3.1-2 of the LRA) of the essential ventilation system. For the internal environments, the LRA identifies carbon/low-alloy steel and copper alloy (zinc less than 15 percent) exposed to air and gas (wetted) less than 140 °F, and copper alloy (zinc less than 15 percent) exposed to raw water, as subject to loss of material aging effect. The LRA also identifies HX-copper alloy (zinc less than 15 percent) exposed to air and gas (wetted) less than 140 °F and raw water environments as subject to loss of heat transfer. Neoprene exposed to air and gas (wetted) less than 140 °F is subject to change in material properties due to elevated temperature. No aging effects were identified for galvanized carbon steel, stainless steel, and aluminum exposed to an air and gas (wetted) less than 140 °F environment.

For the external environments, the LRA identifies carbon/low-alloy steel exposed to an indoor not- air-conditioned environment as subject to loss of material and loss of preload due to stress relaxation. Carbon/low-alloy steel exposed to borated water leaks is subject to the loss of material aging effect. The LRA also identifies neoprene exposed to an indoor not-air-conditioned environment as subject to change in material properties and cracking. The LRA does not identify any aging effects for galvanized carbon steel, neoprene, aluminum, and carbon/low-alloy steel exposed to an indoor air-conditioned environment. Nor were any aging effects identified for galvanized carbon steel and stainless steel exposed to an indoor not-air-conditioned environment or galvanized carbon steel and aluminum exposed to an outdoor environment. Stainless steel exposed to either indoor not-air-conditioned or borated water leaks environments shows no aging effects.

Aging Management Programs

The following AMPs are utilized to manage aging effects in the essential ventilation system:

- Bolting Integrity Program (B2.1.5)
- Boric Acid Corrosion Program (B2.1.6)
- Periodic Surveillance and Preventive Maintenance Program (B2.1.23)
- One-Time Inspection Program (B2.1.21)
- Systems Monitoring Program (B2.1.33)

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

3.3.2.4.10.2 Staff Evaluation

Aging Effects

The staff reviewed the information in Tables 2.3.3-10, 3.4-1, and 3.4-2 for the essential ventilation system. During its review, the staff determined that additional information was needed to complete its review.

LRA Table 3.4-2, line 9, identifies the material for the blower (fan) casing component as galvanized carbon steel. However, in the discussion column of the same row, it refers to stainless steel. In addition, the LRA states that stainless steel exposed to ventilation air (less than 140 °F) would not be expected to exhibit loss of material due to pitting and crevice corrosion. By letter dated March 21, 2003, the staff requested, in RAI 3.4.10-1, the applicant to clarify the discrepancy concerning the material of the component.

In its response, dated May 13, 2003, the applicant stated that LRA Table 3.4-2, line 9, correctly identifies galvanized carbon steel. The discussion column of the same row should have read galvanized carbon steel rather than stainless steel exposed to ventilation air (less than 140 °F). Galvanized carbon steel would also not be expected to exhibit loss of material due to pitting and crevice corrosion. Therefore, no aging effects are applicable and no AMP is required. This was a typographical error.

On the basis of its review, the staff finds that the applicant's response is acceptable because the applicant has clarified that the discrepancy resulted from a typographical error and the material should be galvanized carbon steel as indicated in LRA Table 3.4-2, line 9. The staff considers the issue related to RAI 3.4.10-1 to be resolved.

By letter dated March 21, 2003, the staff issued RAI 3.4-1(a) pertaining to the aging effects of the neoprene (elastomer) components in the containment ventilation system and essential ventilation system and RAI 3.4-1(b) pertaining to the use of the Periodic Surveillance Preventive Maintenance Program for the neoprene components. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.1 of this SER, and the issue is characterized as resolved.

By letter dated March 21, 2003, the staff issued RAI 3.4-2 pertaining to the use of the One-Time Inspection Program for managing the aging effects for components in the containment ventilation system and the essential ventilation system that are included in Table 3.4-1, line 5. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.2 of this SER, and the issue is characterized as resolved.

By letter dated March 21, 2003, the staff issued RAI 3.4-3 pertaining to the use of the Periodic Surveillance and Preventive Maintenance Program for internal surfaces of the components and the use of the System Monitoring Program for external surfaces of the carbon steel components in several of the auxiliary systems in the LRA. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.3 of this SER, and the issue is characterized as resolved.

By letter dated March 21, 2003, the staff issued RAI 3.4-4 pertaining to the aging effects for numerous galvanized carbon steel components that are exposed to various environments in several of the auxiliary systems in the LRA. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.4 of this SER, and the issue is characterized as resolved.

By letter dated March 21, 2003, the staff issued RAI 3.4-5 pertaining to the aging effects of cracking due to SCC for carbon/low-alloy steel fasteners (bolting) in several of the auxiliary systems. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.5 of this 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 essential ventilation system SSCs with the environments described in Tables 2.3.3-9, 3.4-1, and 3.4-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the essential ventilation system.

Aging Management Programs

The applicant credited the following AMPs with managing the aging effects in the essential ventilation system:

- Bolting Integrity Program (3.0.3.3)
- Boric Acid Corrosion Program (3.0.3.4)
- Periodic Surveillance and Preventive Maintenance Program (3.0.3.8)
- One-Time Inspection Program (3.0.3.7)
- Systems Monitoring Program (3.0.3.11)

These AMPs are credited with managing the aging effects of components in several structures and systems and, therefore, are 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 common AMPs is documented in the sections of this SER given in parentheses above.

After evaluating the applicant's AMR for each of the components in the essential ventilation system, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects for this system. For those components identified in Table 3.4-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in LRA Table 3.4-2, the staff verified that the applicant credited AMPs that are appropriate for the identified aging effects.

On the basis of its review, the staff finds that the applicant has credited the appropriate AMPs with managing the aging effects for the materials and environments associated with the essential ventilation system. In addition, the staff reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program and found it to be acceptable, as required by 10 CFR 54.21(d).

3.3.2.4.10.3 Conclusions. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and AMPs credited with managing the aging effects for components in the essential ventilation system, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement provides an adequate program description of the AMPs credited for managing aging in the essential ventilation system to satisfy 10 CFR 54.21(d).

3.3.2.4.11 Cranes, Hoists, and Lifting Devices System

3.3.2.4.11.1 Summary of Technical Information in the Application. The description of the cranes, hoists, and lifting devices system can be found in Section 2.3.3.11 of this SER.
The passive, long-lived components in this system that are subject to an AMR are identified in

LRA Table 2.3.3-11. The components, aging effects, and AMPs are provided in LRA Tables 3.4-1 and 3.4-2.

Aging Effects

Components of the cranes, hoists, and lifting devices 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 2.3.3-11 of the LRA lists individual components of the system including cranes and fasteners (bolting). Fasteners bolting and external surfaces of carbon steel and low-alloy steel components are identified as being subject to loss of material due to boric acid corrosion from exposure to borated water spillage. The cranes include bridge and trolleys and rail systems in the load handling system and are subject to loss of material due to general corrosion and wear.
The applicant also identified fasteners bolting of carbon steel and low-alloy steel components as being subject to cracking due to SCC and loss of preload due to stress relaxation.

Aging Management Programs

The following AMPs are utilized to manage aging effects for the cranes, hoists, and lifting devices system:

- Bolting Integrity Program (B2.1.5)
- Boric Acid Corrosion Program (B2.1.6)
- Periodic Surveillance and Preventive Maintenance Program (B2.1.23)
- Heavy and Light Load (Related to Refueling) Handling Systems Program (B2.1.18)

A description of these AMPs is provided in Appendix B to the LRA. The applicant concluded that the effects of aging associated with the components of the cranes, hoists, and lifting devices will be adequately managed by these AMPs during the period of extended operation.

3.3.2.4.11.2 Staff Evaluation

Aging Effects

The staff reviewed the information in Tables 2.3-11, 3.4-1, and 3.4-2 for cranes, hoists, and lifting devices system. During its review, the staff determined that additional information was needed to complete its review.

In LRA Table 3.4-1, line 13, under the discussion column, the applicant indicated that the component of the cranes, hoists, and lifting devices has the potential for exposure to boric acid spillage and may be subject to the aging effect of loss of material due to boric acid corrosion. However, the AMR results of the cranes, hoists, and lifting devices, as listed in Table 2.3.3-11 of the LRA, does not refer to Table 3.4-1, line 13. By letter dated March 21, 2003, the staff requested, in RAI 3.4.11-1, the applicant to clarify this discrepancy.

In its response, dated May 13, 2003, the applicant stated that this discrepancy results from a typographical error. Table 2.3.3-11 should include, under the component group of fasteners (bolting), aging management reference Table 3.4-1, line 13. On the basis of its review, the staff finds that the applicant's response is acceptable because the applicant clarified that line 13 in Table 3.4-1 should be included as an aging management reference for the fasteners (bolting) in Table 2.3.3-11. The staff considers the issue related to RAI 3.4.11-1 to be 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 cranes, hoists, and lifting devices with the environments described in Tables 2.3.3-9, 3.4-1, and 3.4-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the cranes, hoists, and lifting devices system.

Aging Management Programs

The applicant has credited the following AMPs with managing the aging effects for cranes, hoists, and lifting devices:

- Bolting Integrity Program (3.0.3.3)
- Boric Acid Corrosion Prevention Program (3.0.3.4)
- Periodic Surveillance and Preventive Maintenance Program (3.0.3.8)
- Heavy and Light Load (Related to Refueling) Handling Systems Program (3.3.2.3.5)

With the exception of the Heavy and Light Load (Related to Refueling) Handling Systems Program, these AMPs are credited with managing the aging effects of components in several structures and systems and, therefore, are 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. These common AMPs are evaluated in the sections of this SER given in parentheses above. The Heavy and Light Load (Related to Refueling) Handling Systems Program has been evaluated and found to be appropriate for this system. The staff's evaluation of Heavy and Light Load (Related to Refueling) Handling Systems Program is documented in Section 3.3.2.3.5 of this SER.

After evaluating the applicant's AMR for each of the components in the cranes, hoists, and lifting devices system, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects for this system. For those components identified in Table 3.4-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in LRA Table 3.4-2 , the staff verified that the applicant credited AMPs that are appropriate for the identified aging effects.

On the basis of its review, the staff finds that the applicant has credited the appropriate AMPs with managing the aging effects for the materials and environments associated with cranes, hoists, and lifting devices. In addition, the staff reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program and found it to be acceptable, as required by 10 CFR 54.21(d).

3.3.2.4.11.3 Conclusions. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and AMPs credited with managing the aging effects for components associated with cranes, hoists, and lifting devices, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement provides an adequate program description of the AMPs credited for managing aging of cranes, hoists, and lifting devices to satisfy 10 CFR 54.21(d).

3.3.2.4.12 Treated Water System

3.3.2.4.12.1 Summary of Technical Information in the Application. The description of the treated water system can be found in Section 2.3.3.12 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3.3-12. The components, aging effects, and AMPs are provided in LRA Tables 3.4-1 and 3.4-2.

Aging Effects

Components of the treated water system are described in Section 2.3.3.12 of the submittal. Table 2.3.3-12 of the LRA listed individual components in the treated water system that are within the scope of license renewal and subject to AMR. The components include closure bolting, penetration seal, pump casing, valves, piping, and fittings.

Carbon/low-alloy and stainless steel components in treated water—other environments are identified as being subject to loss of material from general, crevice, and pitting corrosion and MIC. Stainless steel components in containment air and borated water leakage environments have no aging effects requiring management. Copper alloy (zinc less than 15 percent) was identified as being subject to loss of material aging effects in the raw water drainage environment. Carbon/low-alloy steel components were identified as being subject to loss of material aging effects in the treated water leakage environment. Carbon/low-alloy steel fasteners (bolting) were identified to be subject to aging effects due to loss of preload and stress relaxation in the indoor not-air-conditioned environment. The applicant does not identify any aging effects for copper alloy, aluminum, and cast iron in an indoor air-conditioned environment and carbon/low-alloy steel components in an indoor not-air-conditioned environment.

Aging Management Programs

The LRA credited the following AMPs with managing the identified aging effects for the treated water system:

- Boric Acid Corrosion Program (B2.1.6)
- Bolting Integrity Program (B2.1.5)
- Systems Monitoring Program (B2.1.33)
- Water Chemistry Program (B2.1.37)
- One-Time Inspection Program (B2.1.21)

- Periodic Surveillance and Preventive Maintenance Program (B2.1.23)

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

3.3.2.4.12.2 Staff Evaluation

Aging Effects

The staff reviewed the information in Tables 2.3.3-12, 3.4-1, and 3.4-2 for the treated water system. During its review, the staff determined that additional information was needed to complete its review.

In LRA Table 3.4-2, lines 265 and 434, the applicant identified loss of material as an aging effect/mechanism for aluminum, cast iron, or copper alloy components in a raw water drainage environment in the treated water system. The applicant further credited the One-Time Inspection Program as the applicable AMP. By letter dated March 21, 2003, the staff requested, in RAI 3.4.12-1, the applicant to justify why the one-time inspection alone is adequate to manage the aging effects for any of the auxiliary systems' components.

In its response, dated May 13, 2003, the applicant stated that LRA Table 3.4-2, line 265, identifies loss of material as an aging effect for cast iron, and line 434 for copper alloy (zinc less than 15 percent) in a raw water drainage environment, with the One-Time Inspection Program as the applicable program. A discussion of cast iron and copper alloys in treated water environments is provided in the response to RAIs 3.4-4 and 3.4.9-1. The scope of the One-Time Inspection Program is described in LRA Section B2.1.21.1. The program includes managing loss of material and/or loss of structural integrity due to selective leaching on the internal surfaces of piping and components made of gray cast iron, bronze, or brass exposed to treated water or raw water environments. The one-time inspection is performed to verify the presence or absence of aging effects. If the results indicate a potential for loss of intended function during the period of extended operation, the corrective action program will be used to identify and implement any additional corrective actions, which may include further inspection. On the basis of its review, the staff finds that the applicant's response is acceptable because the applicant has clarified the scope of the one-time inspection. The staff considers the issue related to RAI 3.4.12-1 to be resolved.

In LRA Table 3.4-2, line 443, the applicant identified no aging effect for the plastic valve body exposed to the raw water drainage environment and, therefore, no AMP is required. By letter dated March 21, 2003, the staff requested, in RAI 3.4.12-2, the applicant to clarify the type of plastic material of the valve body and provide the technical basis for not considering any aging effect for that specific material from exposure to the raw water drainage environment. The technical basis should include a discussion of the plant-specific operating experience related to the component of concern to support the applicant's conclusion.

In its response, dated May 13, 2003, the applicant stated that as a result of recent plant initiatives to verify the functionality of backflow prevention devices, there are no longer any plastic valve bodies within the scope of license renewal. The applicant also stated that the valves evaluated in Table 3.4-2, lines 441, 442, and 443, and shown on drawing 33013-2681-LR, are now included in Table 3.4-2, lines 429 and 434, which are now the appropriate aging management references for the valves. Lines 429 and 434 are valves made of copper alloy (zinc less than 15 percent) for which the staff's evaluation is discussed in Section 3.3.2.5.7 of this SER. On the basis of its review, the staff finds that the applicant's response is acceptable because the applicant has clarified that those plastic valves no longer exist at Ginna and the replacement valves are made of copper alloy (zinc less than 15 percent). In addition, the staff has reviewed the aging management for copper alloy (zinc less than 15 percent) components and found it to be acceptable as discussed in Section 3.3.2.5.7 of this SER. The staff considers the issue related to RAI 3.4.12-2 to be 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 treated water system SSCs with the environments described in Tables 2.3-12, 3.4-1, and 3.4-2 of the LRA are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the treated water system.

Aging Management Programs

The applicant has credited the following AMPs with managing the aging effects in the treated water system:

- Boric Acid Corrosion Program (3.0.3.4)
- Bolting Integrity Program (3.0.3.3)
- Water Chemistry Control Program (3.0.3.1)
- One-Time Inspection Program (3.0.3.7)
- Systems Monitoring Program (3.0.3.11)
- Periodic Surveillance and Preventive Maintenance Program (3.0.3.8)

These AMPs are credited with managing the aging effects of several components in other structures and systems and, therefore, are 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 common AMPs is documented in the sections of this SER given in parentheses above.

After evaluating the applicant's AMR for each of the components in the treated water system, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects for this system. For those components identified in Table 3.4-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in LRA Table 3.4-2, the staff verified that the applicant credited AMPs that are appropriate for the identified aging effects.

On the basis of its review, the staff finds that the applicant has credited the appropriate AMPs with managing the aging effects for the materials and environments associated with the treated water system. In addition, the staff reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program and found it to be acceptable, as required by 10 CFR 54.21(d).

3.3.2.4.12.3 Conclusions. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and AMPs credited with managing the aging effects for components in the treated water system, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement provides an adequate program description of the AMPs credited for managing aging in the treated water system to satisfy 10 CFR 54.21(d).

3.3.2.4.13 Radiation Monitoring System

3.3.2.4.13.1 Summary of Technical Information in the Application. The description of the radiation monitoring system can be found in Section 2.3.3.13 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3.3-13. The components, aging effects, and AMPs are provided in LRA Tables 3.4-1 and 3.4-2.

Aging Effects

Components of the radiation monitoring system are described in Section 2.3.3.4 of the submittal as being within the scope of license renewal and subject to an AMR. Table 2.3.3-13 of the LRA lists individual components of the system including fasteners (bolting), filter housing, flow element, flow meter, pipes and fittings, pump casings, radiation detector housing, radiation monitor skid, and valve bodies.

Fasteners (bolting) and external surfaces of carbon steel and low-alloy steel components are identified as being subject to loss of material due to boric acid corrosion from exposure to borated water spillage. Stainless steel monitor components are identified as being subject to loss of material due to general corrosion in the raw water environment. Copper alloy is identified as being subject to loss of material due to general corrosion in the air and gas (wetted) less than 140 °F environment. Closure bolting components are identified as being subject to loss of material due to general corrosion, loss of preload due to stress relaxation, and crack initiation and growth due to cyclic loading and SCC. The LRA also states that, at Ginna, there are no bolts with a specified minimum yield strength greater than 150 ksi in the auxiliary systems and, therefore, SCC is not an applicable aging mechanism. Carbon/low-alloy steel components are identified as being subject to loss of material due to general corrosion in an indoor not-air-conditioned environment.

The LRA states that exposure of the components constructed of stainless steel, CASS, and aluminum to indoor not-air-conditioned, air and gas (wetted) less than 140 °F environments does not result in any aging effects requiring management. No aging effects are identified for copper alloy (zinc less than 15 percent) exposed to an indoor not-air-conditioned environment.

Aging Management Programs

The following AMPs are utilized to manage aging effects for the radiation monitoring system:

- Bolting Integrity Program (B2.1.5)
- Boric Acid Corrosion Program (B2.1.6)
- One-Time Inspection Program (B2.1.21)
- Periodic Surveillance and Preventive Maintenance Program (B2.1.23)

The applicant concluded that the effects of aging associated with the components of the radiation monitoring system will be adequately managed by these AMPs during the period of extended operation.

3.3.2.4.13.2 Staff Evaluation

Aging Effects

The staff reviewed the information in Tables 2.3.3-13, 3.4-1, and 3.4-2 for the radiation monitoring system. During its review, the staff determined that additional information was needed to complete its review.

By letter dated March 21, 2003, the staff issued RAI 3.3-4 pertaining to the aging effect/mechanism for the copper alloy components in the service water systems that are exposed to an indoor not-air-conditioned environment. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.7 of this 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 RAI, the staff finds that the aging effects that result from contact of the radiation monitoring system SSCs with the environments described in Tables 2.3.3-13, 3.4-1, and 3.4-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the radiation monitoring system.

Aging Management Programs

The applicant has credited the following AMPs with managing the aging effects in the radiation monitoring system:

- Bolting Integrity Program (3.0.3.3)
- Boric Acid Corrosion Program (3.0.3.4)
- One-Time Inspection Program (3.0.3.7)
- Periodic Surveillance and Preventive Maintenance Program (3.0.3.8)

These AMPs are credited with managing the aging effects of components in several structures and systems and, therefore, are 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 common AMPs is documented in the sections of this SER given in parentheses above.

After evaluating the applicant's AMR for each of the components in the radiation monitoring system, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects for this system. For those components identified in Table 3.4-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in LRA Table 3.4-2, the staff verified that the applicant credited AMPs that are appropriate for the identified aging effects.

On the basis of its review, the staff finds that the applicant has credited the appropriate AMPs with managing the aging effects for the materials and environments associated with the radiation monitoring system. In addition, the staff reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program and found it to be acceptable, as required by 10 CFR 54.21(d).

3.3.2.4.13.3 Conclusions. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and AMPs credited with managing the aging effects for components in the radiation monitoring system, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement provides an adequate program description of the AMPs credited with managing aging in the radiation monitoring system to satisfy 10 CFR 54.21(d).

3.3.2.4.14 Circulating Water System

As described in Section 2.3.3.14 of the LRA, those portions of the circulating water (CW) system that support the delivery of lake water sufficient for the use of service water and fire water pumps are evaluated within the service water system; those portions of the circulating water system that provide circulating water flood detection are evaluated within the reactor protection system. Consequently, within the system evaluation boundary, there are no components that perform license renewal intended functions.

The staff review of the scoping and screening process in LRA Section 2.3.3.14 concluded that within the system evaluation boundary, no circulating water system components are within the scope of license renewal. Therefore, within the system evaluation boundary, none of the circulating water system components are subject to an AMR.

3.3.2.4.15 Chilled Water System

As described in Section 2.3.3.15 of the LRA, the applicant's scoping and screening review concluded that within the system evaluation boundary for the chilled water system, there are no components that perform license renewal intended functions; therefore, none of the chilled water system components are subject to an AMR.

The staff review of the scoping and screening process in LRA Section 2.3.3.15 concluded that no chilled water system components are within the scope of license renewal. Therefore, none of the chilled water system components are subject to an AMR.

3.3.2.4.16 Fuel Handling System

As described in Section 2.3.3.16 of the LRA, the applicant's scoping and screening review concluded that within the system evaluation boundary for the fuel handling system, there are no components that perform license renewal intended functions; therefore, none of the fuel handling system components are subject to an AMR.

The staff review of the scoping and screening process in LRA Section 2.3.3.16 concluded that no fuel handling system components are within the scope of license renewal. Therefore, none of the fuel handling system components are subject to an AMR.

3.3.2.4.17 Plant Sampling System

As described in Section 2.3.3.17 of the LRA, those portions of the plant sampling system that provide containment isolation are evaluated with the containment isolation system. Consequently, within the system evaluation boundary, there are no components that perform license renewal intended functions.

The staff review of the scoping and screening process in LRA Section 2.3.3.17 concluded that no plant sampling components are within the scope of license renewal. Therefore, none of the plant sampling components are subject to an AMR.

3.3.2.4.18 Plant Air System

As described in Section 2.3.3.18 of the LRA, the applicant's scoping and screening review concluded that within the system evaluation boundary for the plant air system, there are no components that perform license renewal intended functions; therefore, none of the plant air system components are subject to an AMR.

The staff review of the scoping and screening process in LRA Section 2.3.3.18 concluded that no plant air system components are within the scope of license renewal. Therefore, none of the plant air system components are subject to an AMR.

3.3.2.4.19 Nonessential Ventilation System

As described in Section 2.3.3.19 of the LRA, the applicant's scoping and screening review concluded that within the system evaluation boundary for the nonessential ventilation system, there are no components that perform license renewal intended functions; therefore, none of the nonessential ventilation system components are subject to an AMR.

The staff review of the scoping and screening process in LRA Section 2.3.3.19 concluded that no nonessential ventilation system components are within the scope of license renewal. Therefore, none of the nonessential ventilation system components are subject to an AMR.

3.3.2.4.20 Site Service and Facility Support System

As described in Section 2.3.3.20 of the LRA, the applicant's scoping and screening review concluded that within the system evaluation boundary for the site service and facility support system, there are no components that perform license renewal intended functions; therefore, none of the site service and facility support system components are subject to an AMR.

The staff review of the scoping and screening process in LRA Section 2.3.3.20 concluded that no site service and facility support system components are within the scope of license renewal. Therefore, none of the site service and facility support system components are subject to an AMR.

3.3.2.5 General Aging Management Review Issues

3.3.2.5.1 Neoprene (Elastomer) Components

(a) The containment ventilation and essential ventilation systems discussed in Section 2.3 of the LRA include neoprene (elastomer) components in the systems. Normally, these systems contain elastomer materials in duct seals, flexible collars between ducts and fans, rubber boots, etc. For some plant designs, elastomer components are used as vibration isolators to prevent transmission of vibration and dynamic loading to the rest of the system. In LRA Table 3.4-1, line 2, the applicant identified the aging effects of hardening, cracks, loss of strength due to elastomer degradation, and loss of material due to wear. In the discussion column of that row, the applicant credits the One-Time Inspection Program and the Periodic Surveillance and Preventive Maintenance Program for managing the hardening, cracking, and loss of strength aging effects. The applicant also credited the Systems Monitoring Program for managing the aging effect of loss of material due to wear. The staff noted that the scope of the One-Time Inspection Program as described on pages B-38 and B-39 of the LRA does not include hardening, cracking, and loss of strength as the aging effects of concern and does not include components that are exposed to air and gas.

By letter dated March 21, 2003, the staff issued RAI 3.4-1(a) to request the applicant to (1) clarify how the one-time inspection is utilized to manage aging effects for components included in Table 3.4-1, line 2; (2) clarify whether both the One-Time Inspection Program and the Periodic Surveillance and Preventive Maintenance Program are used for managing these aging effects; and (3) if only one of these two programs is credited for any single component, justify why one-time inspection alone is adequate to manage the aging effects and include a discussion of the plant-specific operating experience related to the components of concern to support this conclusion.

In its response to RAI 3.4-1(a), dated June 10, 2003, the applicant stated that the Periodic Surveillance and Preventive Maintenance Program is credited with managing aging effects such as hardening, cracking, and loss of strength for elastomeric materials in ventilation systems such as duct seals, flexible collars, rubber boots, etc. The applicant further stated that the scope of the Periodic Surveillance and Preventive Maintenance Program now includes inspections of these components. Vibration dampeners were evaluated under the component support commodity group and are included in Table 2.4.2-12 under component group CSUPP-ELAST-INT.

In its clarification to C-RAI 3.4-1, dated July 11, 2003, the applicant provided further clarifications of operating experience related to this issue. The applicant stated that a review of plant-specific operating experience has revealed that a number of maintenance work orders were released during the period 2001 to 2003 for repair of cracks, tears, splits, and other degraded conditions in elastomeric components in ventilation ductwork such as flexible collars, expansion joints, rubber boots, etc. The recent identification of these conditions led to the conclusion that these components should be included in the scope of the Periodic Surveillance and Preventive Maintenance Program. However, operating experience indicates that there are other elastomeric components in ventilation systems such as gasket seals that have not exhibited degradation. These components are appropriately included under the scope of the One-Time Inspection Program.

On the basis of its review, the staff finds that the applicant's response is acceptable because the applicable elastomeric components in the ventilation systems are now included in the scope of the Periodic Surveillance and Preventive Maintenance Program. The staff considers the issue related to RAI 3.4-1(a) to be resolved.

(b) The staff also noted that the program description of the Periodic Surveillance and Preventive Maintenance Program on pages B-42 and B-43 of the LRA includes loss of seal but not hardening and loss of strength as the aging effects of concern. By letter dated March 21, 2003, the staff issued RAI 3.4-1(b) to request the applicant to (1) clarify whether loss of seal includes hardening and loss of strength and (2) provide the frequency of the subject inspection described in LRA Sections B2.1.23 and B2.2.33 for the applicable neoprene components and include a discussion of the operating history to demonstrate that the applicable aging degradations will be detected prior to the loss of their intended function.

In its response to RAI 3.4-1(b), dated June 10, 2003, the applicant stated that the loss of seal aging effect is identified in NUREG-1801 as applicable to elastomeric components. Loss of seal may occur as a result of changes in properties of elastomers. Changes in properties may be due to hardening and cracking mechanisms which result from prolonged exposure of elastomers to elevated temperatures (greater than 95 °F) and ionizing radiation fields (greater than 10^6 rads). Therefore, loss of seal is a result of changes in properties which include hardening and loss of strength. The applicant further stated that, as discussed in (a) above, the inspections are now included in the scope of the Periodic Surveillance and Preventive Maintenance Program and are to be performed on a 6-year frequency. Moreover, the applicant stated that this frequency will be evaluated and adjusted as necessary based upon the inspection results.

On the basis of its review, the staff finds that the applicant's response is acceptable because the applicant has adequately clarified why one-time inspection alone is adequate to manage the aging effects of certain elastomeric components in ventilation systems and the applicant's conclusion is supported by the operating experience. The staff considers the issue related to RAI 3.4-1(b) to be resolved.

3.3.2.5.2 One-Time Inspection Program Used for Components Exposed to Air and Gas

In LRA Tables 2.3.3-9 and 2.3.3-10, the AMR results for numerous components in the containment ventilation and essential ventilation systems refer to LRA Table 3.4-1, line 5. These components include carbon/low-alloy steel that is exposed to air and gas (wetted) less than 140 °F. Table 3.4-1, line 5, credits the One-Time Inspection Program, among others, for managing aging effects of loss of material due to general, pitting, and crevice corrosion and MIC for the internal environments of ventilation systems, diesel fuel oil systems, and EDG systems. It credits the Systems Monitoring Program for managing the aging effect of loss of material for external surfaces of carbon steel components.

The staff noted that the scope of the One-Time Inspection Program, as described on pages B-38 and B-39 of the LRA, does not include components that are exposed to air and gas. In addition, LRA Section B2.1.21, "One Time Inspection," states that the Ginna One-Time Inspection Program will include measures to verify the effectiveness of an existing AMP and confirm the absence of an aging effect. By letter dated March 21, 2003, the staff issued RAI 3.4-2 to request the applicant to (1) clarify how the One-Time Inspection Program is utilized to manage aging effects for the components in these two ventilation systems that are included in Table 3.4-1, line 5; (2) clarify whether both the One-Time Inspection Program and the other AMPs are used for managing these aging effects, and (3) if only one of these AMPs is credited for any single component, justify why the One-Time Inspection Program alone is adequate to manage the aging effects and include a discussion of the plant-specific operating experience related to the components of concern to support this conclusion.

In its response to RAI 3.4-2, dated June 10, 2003, the applicant stated that Table 3.4-1, line 5, "Components in ventilation systems," includes carbon steel fan housings, damper housings, filter housings, etc., in the containment and essential ventilation systems. The temperature of these housings would be expected to be the same as that of the ambient air on either side and thus no condensation would be expected to occur on the housing surfaces. Therefore, the applicant concluded that aging effects, if any, from exposure of carbon steel to this environment would be expected to occur very slowly. A one-time inspection will be performed on these components and the results evaluated. The applicant further stated that, if these inspections reveal evidence of age-related degradation, appropriate corrective actions will be taken and the specific components will be included within the scope of the Periodic Surveillance and Preventive Maintenance Program.

In its clarification to C-RAI 3.4-2, dated July 11, 2003, the applicant provided further clarifications as discussed below.

- The applicant stated that the One-Time Inspection Program is credited with managing the effects of aging only for the components in the two ventilation systems that are included in Table 3.4-1. These components include carbon steel fan housings, damper housings, and filter housings in the containment and essential ventilation systems. The internal environment of these components is air and gas (wetted) less than 140 °F, and the external environment is containment air, which is the same as the internal environment. The temperature of these housings would be expected to be the same as that of the ambient air on either side. Therefore, no condensation would be expected to occur on the housing surfaces, and the aging effects, if any, from exposure of carbon steel to this environment would be expected to occur very slowly. The applicant also stated that a commitment (reference item 7 in Appendix A to this SER) was made to perform a one-time inspection of the internal surfaces of these components and evaluate the inspection results. If no evidence of age-related degradation is found, no further inspections are planned. Moreover, the applicant stated that a further commitment was made to take appropriate corrective action and include these components in the scope of the Periodic Surveillance and Preventive Maintenance Program only if evidence of age-related degradation was found.

  In addition, the applicant stated that for components in the diesel fuel oil system, the Fuel Oil Chemistry Program and the Periodic Surveillance and Preventive Maintenance Program are credited with managing the effects of aging for components exposed to the fuel oil environment.

  The applicant also stated that for components exposed to service water and lubricating oil in the EDG system, the Periodic Surveillance and Preventive Maintenance Program is credited with managing the effects of aging. For components in the EDG system that are exposed to component cooling water, the Periodic Surveillance and Preventive Maintenance Program and the Closed-Cycle (Component) Cooling Water System Program are credited with managing the effects of aging.

- The applicant stated that for external surfaces of all components, the Systems Monitoring Program is credited with managing the aging effect loss of material.
- The applicant stated that a review of plant-specific operating experience revealed that no evidence of age-related degradation has ever been reported for carbon steel components such as fan housings, damper housings, and filter housings in the containment and essential ventilation systems.

On the basis of its review, the staff finds that the applicant’s response is acceptable because the applicant has provided an adequate technical basis for not considering the aging effects of carbon steel components exposed to air and gas and the plant-specific operating experience supported that conclusion. The staff considers the issue related to RAI 3.4-2 to be resolved.

3.3.2.5.3 Leakage Monitoring in AMPs

Table 3.4-1, line 5 of the LRA, credits the Periodic Surveillance and Preventive Maintenance Program, among others, with managing aging effects for the internal surfaces of components in ventilation systems, diesel fuel oil systems, and the EDG system and credits the Systems Monitoring Program with managing the aging effect of loss of material for external surfaces of carbon steel components. The staff notes that Appendices B2.1.23 and B2.1.33, under "Parameters Monitored/Inspected," include leakage as an example of parameters monitored/inspected. The staff believes that the presence of leakage from a component would indicate that the component's ability to perform its intended function as a pressure boundary may have been compromised. By letter dated March 21, 2003, the staff requested, in RAI 3.4-3, the applicant to (1) clarify whether any of the auxiliary systems components for which the Periodic Surveillance and Preventive Maintenance Program and Systems Monitoring Program are credited rely on the monitoring of leakage, (2) discuss why visual inspection technique alone is sufficient in detecting the aging effects described in Appendices B2.1.23 and B2.1.33, without including other NDE procedures, such as volumetric and/or surface techniques, and (3) discuss the operating history of the above components to demonstrate that the applicable aging effects will be adequately managed prior to the loss of their intended functions.

In its response, dated May 13, 2003, the applicant stated that leaking inspections initiated by the Periodic Surveillance and Preventive Maintenance Program are just one of several methods used for detecting and monitoring the effects of aging. Other techniques include visual examinations, supplemental surface and volumetric examinations deemed necessary by engineering evaluation, volumetric (eddy current) examinations of heat exchanger tubing, and other periodic volumetric examinations including radiography and ultrasonic testing to verify wall thickness as required by the Open-Cycle Cooling Water System Program. The applicant further stated that the identification of leaks and the evaluation of the consequences of those leaks are the condition where leakage monitoring is an important technique utilized for component aging management.

In its July 11, 2003 response to C-RAI 3.4-1, the applicant provided further clarifications of the operating experience related to this issue. The applicant stated that a review of plant-specific operating experience was performed during the AMR process and was documented in aging management review reports and in aging management program basis documents. This review indicated that evidence of minor leakage at bolted closures has been identified by inspections performed during system engineer walkdowns under the Systems Monitoring Program, during maintenance activities performed under the Periodic Surveillance and Preventive Maintenance Program, and during leakage examinations performed under the ASME Section XI Inservice Inspection Program. The applicant further stated that the identification of these leaks and the evaluation of the consequences of those leaks under the Corrective Action Program have been an effective element in managing component aging and, therefore, in maintaining component integrity before loss of intended function occurs.

On the basis of its review, the staff finds that the applicant's response is acceptable because leakage detection is just one of several methods used by the applicant for detecting and monitoring the effects of aging and the applicant's discussions of using leakage monitoring for component aging management are reasonable and are supported by the plant-specific operating experience. The staff considers the issue related to RAI 3.4-3 to be resolved.

3.3.2.5.4 Aging Effects for Galvanized Carbon Steel

Table 3.4-2 of the LRA identifies no aging effects for numerous galvanized carbon steel components (e.g., lines 3, 4 ,5, 6, 61, 62, 163, and 164) that are exposed to the environments of air and gas, air and gas (wetted) less than 140 °F, containment, or indoor not-air-conditioned. The LRA states that no AMP is required, and it cites a site-specific review of standard industry guidance for aging evaluation of mechanical systems and components as the basis for this conclusion. It indicates that galvanized carbon steel exposed to ventilation air (less than 140 °F) would be expected to exhibit minimal deterioration of the zinc coating.

By letter dated March 21, 2003, the staff requested, in RAI 3.4-4, the applicant to (1) provide the documented evidence for the above-mentioned site-specific reviews of the standard industry guidance, (2) clarify the discrepancy in line 62, where, under "Discussion," the temperature criteria of "T<140 °F" is not consistent with "T>140 °F" as listed under "Environment," and (3) provide similar additional information for "muffler" in lines 193 and 194.

In its response, dated May 13, 2003, the applicant indicated that the *ASM Metals Handbook*, Volume 13, "Corrosion," states the following:

> The behavior of zinc coatings during atmospheric exposure has been closely examined in tests conducted throughout the world. Precise comparison of corrosion behavior in atmospheres is complex because of many factors involved. It is generally accepted that the corrosion rate of zinc is low; it ranges from 0.005 mils/yr in dry rural atmospheres to 0.5 mils/yr in most industrial atmospheres. Zinc owes its high degree of resistance to atmospheric corrosion to the formation of insoluble basic carbonate films.

The applicant also stated that zinc is used as a protective coating for carbon steels because of its corrosion resistance in external environments and because it provides galvanic protection of the carbon steel base metal at discontinuities or areas of coating damage. The corrosion products of zinc tend to be alkaline and thereby neutralize normal acidic moisture that occurs in outdoor or industrial environments. In the pH range 6–12, zinc undergoes negligible corrosion under most environmental conditions. When exposed to water, the corrosion resistance of zinc is maintained in this pH range. Temperature also affects the corrosion rate of galvanized steel. Between 140 °F and 200 °F, the corrosion products are significantly more conductive than at temperatures outside this range, and therefore, degradation of the zinc coating can occur on wetted surfaces in this temperature range. However, below 140 °F, and certainly at normal ambient temperatures in air and gas, containment, and indoor not-air-conditioned environments, where typical temperatures range from 75–90 °F, minimal deterioration of the zinc coating would be expected on galvanized carbon steel components.

The applicant further stated that a review of plant-specific operating experience revealed no evidence of age-related degradation of galvanized steel components exposed to air and gas, air and gas wetted less than 140 °F, containment, and indoor not-air-conditioned environments. The applicant also indicated that there is a typographical error in the environment description for line 62, "expansion joint," and line 193, "muffler," in Table 3.4-2. The correct environment is "air and gas (wetted) < 140 °F."

On the basis of its review, the staff finds that the applicant's response is acceptable because the basis for not considering the aging effects of galvanized carbon steel components exposed to air and gas, air and gas wetted less than 140 °F, containment, and indoor not-air-conditioned environments is consistent with the industry's experience. Furthermore, the applicant's conclusion is supported by the plant-specific operating experience. The staff considers the issue related to RAI 3.4-4 to be resolved.

3.3.2.5.5 Cracking Due to SCC for Fasteners (Bolting)

Table 3.4-2 of the LRA, line 79, identifies the aging effect of cracking due to SCC for carbon/low-alloy steel fasteners (bolting) in the containment ventilation, essential ventilation, and radiation monitoring systems from exposure to an indoor not-air-conditioned environment and identified the Bolting Integrity Program as managing this aging effect. However, the discussion column of that row indicates that SCC is not an applicable aging effect/mechanism. By letter dated March 21, 2003, the staff requested, in RAI 3.4-5, the applicant to clarify this discrepancy.

In its response to RAI 3.4-5, dated May 13, 2003, the applicant stated that LRA Table 3.4-2, line 79, identifies cracking due to SCC as an aging effect requiring management for carbon/low-alloy steel fasteners (bolting) in the containment ventilation, essential ventilation, and radiation monitoring systems exposed to an indoor not-air-conditioned environment. The basis for this identification lies in NUREG 1801, Chapter VII, Item I.2-b, "Closure Bolting in High Pressure or High Temperature Systems." The applicant indicated that LRA Table 3.4-2, line 79, is incorrectly associated with bolting in Tables 2.3.3-9, 2.3.3-10, and 2.3.3-13. These systems are not high-pressure or high-temperature systems.

On the basis of its review, the staff finds that the applicant's response is acceptable because the applicant has adequately clarified that LRA Table 3.4-2, line 79, is incorrectly associated with bolting in Tables 2.3.3-9, 2.3.3-10, and 2.3.3-13. The staff considers the issue related to RAI 3.4-5 to be resolved.

3.3.2.5.6 Neoprene Pipes

Table 3.4-2 of the LRA, lines 65 and 225–228, do not identify aging effects for neoprene pipes exposed to oil and fuel oil, raw water, and treated water—other environments that require management. This determination may not be supported by industry experience. Similar to being exposed to a containment or indoor not-air-conditioned environment, as in lines 220–224, the neoprene material, when exposed to the above environments, may be susceptible to changes in material properties and also to cracking. By letter dated March 21, 2003, the staff requested, in RAI 3.4-6, the applicant to provide the basis for not considering change in material properties and cracking as applicable aging effects for the neoprene piping components included in Table 3.4-2, lines 65 and 225–228.

In its response, dated May 13, 2003, the applicant stated that lines 65 and 225–228 address aging effects due to exposure of neoprene to internal environments of oil and fuel oil, raw water, and treated water—other. Standard industry guidance indicates that neoprene exhibits excellent resistance to oils, raw and treated waters, chemicals, sunlight, and ozone. The applicant further stated that changes in material properties of neoprene rubber occur as a result of exposure to elevated temperatures and ionizing radiation. The threshold temperature for aging mechanisms which cause changes in material properties of neoprene is conservatively taken to be 95 °F. The threshold fluence value for changes in material properties of neoprene due to exposure to ionizing radiation is conservatively taken to be 10^6 rads. Therefore, the applicant concluded that there are no aging effects requiring management for neoprene exposed to internal environments of oil and fuel oil and raw and treated waters at temperatures below 95 °F and exposed to ionizing radiation fluence less than 10^6 rads. Furthermore, a review of plant-specific operating experience revealed no evidence of age-related degradation of neoprene exposed to these environments.

On the basis of its review, the staff finds that the applicant's response is acceptable because the applicant has provided an adequate basis for not considering aging effects due to exposure of neoprene to internal environments of oil and fuel oil, raw water, and treated water—other, and the applicant's conclusion is supported by the plant-specific operating experience. The staff considers the issue related to RAI 3.4-6 to be resolved.

3.3.2.5.7 Copper Alloy (Zinc Less Than 15 Percent) Components

In LRA Table 3.4-2, lines 114, 118, 155, 167, 180, 195, 212, and 266, as well as Table 3.3-2, lines 44, 45, 67, 88, and 89, the applicant identified no aging effects that require management for copper alloy (zinc less than 15 percent) pipe, thermowell, pump casing, strainer housing, and valve body exposed to containment or indoor not-air-conditioned environments. However, this determination may not be supported by industry experience, as the copper alloy material may be susceptible to corrosion in a sheltered, moisture environment. By letter dated March 21, 2003, the staff requested, in RAI 3.3-4, the applicant to provide the basis for this determination.

In its response, dated May 13, 2003, the applicant stated that copper and copper alloy materials (brasses and bronzes) with zinc less than 15 percent display excellent resistance to atmospheric corrosion in a variety of environments, including industrial, marine, and rural atmospheres. The *ASM Metals Handbook*, Volume 13, "Corrosion," states, "Comprehensive tests conducted over a 20-year period under the supervision of ASTM, as well as many service records, have confirmed the suitability of copper and copper alloys for atmospheric exposure." The applicant also stated that the corrosion rate data published in Volume 13 of the *ASM Metals Handbook* indicate that corrosion rates range from .002 mils/yr in rural environments to approximately 0.1 mils/yr in industrial/marine environments. These rates are essentially negligible. Plant-specific operating experience at Ginna has revealed no evidence of corrosion-related degradation of copper alloy components exposed to indoor not-air-conditioned and containment environments. In addition, the applicant further stated that atmospheric conditions at Ginna are benign and certainly less severe than industrial or marine environments where these materials display excellent resistance to corrosion, including pitting and crevice corrosion. Therefore, plant-specific operating experience confirms the absence of aging effects for copper and copper alloys exposed to ambient atmospheric conditions at Ginna.

On the basis of its review, the staff finds that the applicant's response is acceptable because the applicant has provided an adequate technical basis for not identifying an aging effect for copper alloy material exposed to ambient atmospheric conditions at Ginna and the applicant's conclusion was supported by the plant-specific operational experience. The staff considers the issue related to RAI 3.3-4 to be closed.

3.3.3 Staff Evaluation

On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and the AMPs credited with managing the aging effects for the auxiliary systems, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation. The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement for Ginna provides an adequate program description of the AMPs credited with managing aging effects, as required by 10 CFR 54.21(d).

3.4 Steam and Power Conversion Systems

This section addresses the aging management of the components of the steam and power conversion systems group. The systems that make up the steam and power conversion systems group are described in the following SER sections:

- Main and Auxiliary Steam (2.3.4.1)
- Feedwater and Condensate (2.3.4.2)
- Auxiliary Feedwater (2.3.4.3)
- Turbine Generator and Supporting (2.3.4.4)

As discussed in Section 3.0.1 of this SER, the components in each of these steam and power conversion systems are included in one of two LRA tables. Table 3.5-1 consists of steam and power conversion system components that are evaluated in the GALL Report. Table 3.5-2 consists of steam and power conversion system components that are not evaluated in the GALL Report.

3.4.1 Summary of Technical Information in the Application

In LRA Section 3.5, the applicant described its AMRs for the steam and power conversion systems group at Ginna Station. The description of the systems that make up this group can be found in LRA Section 2.3.4. The passive, long-lived components in the steam and power conversion systems that are subject to an AMR are identified in LRA Tables 2.3.4-1, 2.3.4-2, 2.3.4-3, and 2.3.4-4.

The applicant’s AMRs included an evaluation of plant-specific and industry operating experience. The plant-specific evaluation included reviews of inservice inspection reports and corrective action reports to identify aging effects that require management. These reviews concluded that the aging effects requiring management, based on Ginna Station operating experience, were consistent with aging effects identified in GALL. The applicant’s review of industry operating experience included a review of operating experience through 2002. The results of this review concluded that the aging effects requiring management, based on industry operating experience, were consistent with the aging effects identified in GALL. The applicant’s ongoing review of plant-specific and industry-wide operating experience is conducted in accordance with the Ginna Station Operating Experience Program.

3.4.2 Staff Evaluation

In Section 3.5 of the LRA, the applicant describes its AMR for the SPCS at Ginna Station. The staff reviewed Section 3.5 to determine whether the applicant has provided sufficient information to demonstrate that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the period of extended operation, in accordance with the requirements of 10 CFR 54.21(a)(3), for the SPCS components that are determined to be within the scope of license renewal and subject to an AMR.

The applicant referenced the GALL Report in its AMR. The staff has previously evaluated the adequacy of the aging management of SPCS components for license renewal, as documented in the GALL Report. Thus, the staff did not repeat its review of the matters described in the GALL Report, except to ensure that the material presented in the LRA was applicable and to verify that the applicant had identified the appropriate programs as described and evaluated in the GALL Report. The staff evaluated those aging management issues recommended for further evaluation in the GALL Report. The staff also reviewed aging management information submitted by the applicant that was different from that in the GALL Report or was not addressed in the GALL Report. Finally, the staff reviewed the UFSAR Supplement to ensure that it provided an adequate description of the programs credited with managing aging for the SPCS components.

In LRA Section 3.5, the applicant summarized the results of its AMR of the SPCS at Ginna Station. Table 3.4-1 provides a summary of the staff's evaluation of components, aging effects/mechanisms, and AMPs listed in LRA Section 3.5 that are addressed in the GALL Report.

Table 3.4-1 Staff Evaluation Table for Ginna Station Steam and Power Conversion System Components Evaluated in the GALL Report

Component Group	Aging Effect/Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
(1) Piping and fittings in main feedwater line, steam line, and AFW piping (PWR only)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	TLAA in LRA Section 4.3	Consistent with GALL. GALL recommends further evaluation (see staff evaluation in Section 3.4.2.2.1 below)
(2) Piping and fittings, valve bodies and bonnets, pump casings, tanks, tubes, tubesheets, channel head, and shell (except main steam system)	Loss of material due to general (carbon steel only), pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Water Chemistry Control and Periodic Surveillance and Preventive Maintenance	GALL recommends further evaluation (see staff evaluation in Section 3.4.2.2.2 below)
(3) AFW piping	Loss of material due to general, pitting, and crevice corrosion, MIC, and biofouling	Plant specific	Not applicable	See staff evaluation in Section 3.4.2.2.3 below.

Component Group	Aging Effect/Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
(4) Oil coolers in AFW system (lubricating oil side possibly contaminated with water)	Loss of material due to general (carbon steel only), pitting, and crevice corrosion, and MIC	Plant specific	Periodic Surveillance and Preventive Maintenance	Consistent with GALL. GALL recommends further evaluation (see staff evaluation in Section 3.4.2.2.5 below.)
(5) External surface of carbon steel components	Loss of material due to general corrosion	Plant specific	Systems Monitoring	Consistent with GALL. GALL recommends further evaluation (see staff evaluation in Section 3.4.2.2.4 below)
(6) Carbon steel piping and valve bodies	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion	Flow-Accelerated Corrosion	Consistent with GALL (see staff evaluation in Section 3.4.2.1 below)
(7) Carbon steel piping and valve bodies in main steam system	Loss of material due to pitting and crevice corrosion	Water Chemistry	Water Chemistry	Consistent with GALL (see staff evaluation in Section 3.4.2.1 below)
(9) Heat exchangers and coolers/condensers serviced by open-cycle cooling water	Loss of material due to general (carbon steel only), pitting, and crevice corrosion, MIC, and biofouling; buildup of deposit due to biofouling	Open-Cycle Cooling Water System	Periodic Surveillance and Preventive Maintenance and Open-Cycle Cooling (Service) Water System	See staff evaluation in Sections 3.4.2.4.5.2 and 3.4.2.4.5.7 below)
(10) Heat exchangers and coolers/condensers serviced by closed-cycle cooling water	Loss of material due to general (carbon steel only), pitting, and crevice corrosion	Closed-Cycle Cooling System	Not applicable	There are no heat exchangers in the SPCS that are serviced by closed-cycle cooling water at Ginna Station.
(11) External surface of aboveground condensate storage tank	Loss of material due to general (carbon steel only), pitting, and crevice corrosion	Aboveground Carbon Steel Tanks	Not applicable	The aboveground CST at Ginna Station is not in scope of license renewal.
(12) External surface of buried condensate storage tank and AFW piping	Loss of material due to general, pitting, and crevice corrosion, and MIC	Buried Piping and Tanks Surveillance or Buried Piping and Tanks Inspection	Not applicable	There are no buried tanks or piping in the SPCS at Ginna Station.

Component Group	Aging Effect/Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
(13) External surface of carbon steel components	Loss of material due to boric acid corrosion	Boric Acid Corrosion	Boric Acid Corrosion	Consistent with GALL (see staff evaluation in Section 3.4.2.1 below)

3.4.2.1 Aging Management Evaluations in the GALL Report That Are Relied on for License Renewal, Which Do Not Require Further Evaluation

For component groups evaluated in the GALL Report for which the applicant has claimed consistency with GALL, and for which the GALL Report does not recommend further evaluation, the staff sampled components in these groups to determine whether the plant-specific components contained in these GALL component groups were bounded by the GALL evaluation. The staff also sampled component groups to determine whether the applicant had properly identified those component groups in the GALL Report that were not applicable to its plant. The staff identified several areas where additional information or clarification was needed. The staff's evaluation of the applicants responses to those RAIs is included in Section 3.4.2.4 of this SER.

On the basis of its review, the staff has verified the applicant's claim of consistency with the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 50.21(a)(3).

3.4.2.2 Aging Management Evaluations in the GALL Report That Are Relied on for License Renewal, for Which GALL Recommends Further Evaluation

For component groups evaluated in the GALL Report for which the applicant has claimed consistency with GALL, and for which the GALL Report recommends further evaluation, the staff reviewed the applicant’s evaluation to determine whether it adequately addressed the issues for which GALL recommended further evaluation. In addition, the staff sampled components in these groups to determine whether the plant-specific components contained in these GALL Report component groups were bounded by the GALL Report evaluation.

The GALL Report indicates that further evaluation should be performed in the areas described in the following sections.

3.4.2.2.1 Cumulative Fatigue Damage

Fatigue is a TLAA as defined in 10 CFR 54.3. All TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The staff’s evaluation of this TLAA is documented in Section 4.3 of this SER, following the guidance in Section 4.3 of the SRP-LR.

Table 3.5-1, Item 1, of the LRA identifies components in the main feedwater, steam line, and auxiliary feedwater (AFW) piping as requiring aging management for cumulative fatigue damage and states that evaluations of these components are consistent with the GALL Report. Since the GALL Report recommends aging management of cumulative fatigue for the main steam, feedwater, and AFW components and the LRA states it is consistent with the GALL Report, Tables 2.3.4-1 through 2.3.4-4 of the LRA should identify these components as being managed for cumulative fatigue. However, Tables 2.3.4-1 through 2.3.4-4 do not identify any SPCS components that are managed for cumulative fatigue. The staff issued RAI 3.5-1 requesting the applicant to explain why Tables 2.3.4-1 through 2.3.4-4 do not identify any SPCS components that are managed for cumulative fatigue and also to explain if the main steam, main feed, and AFW system piping are evaluated for thermal fatigue using the method described in Section 4.3.2 of the LRA.

In its response, by letter dated May 13, 2003, the applicant stated the following:

> Links to Table 3.5-1, item 1 of the LRA were inadvertently omitted in Tables 2.3.4-1 through 2.3.4-4 to identify cumulative fatigue damage as an aging effect requiring management for piping and fittings in the main feedwater, main steam, and AFW steam and power conversion systems components. Section 4.3.2 of the LRA entitled "ANSI B31.1 Piping" states that the balance-of-plant piping was originally designed to the requirements of USAS B31.1, Power Piping Code. Balance-of-plant piping includes main steam, main feedwater, and AFW steam and power conversion components. Components in these systems were evaluated for thermal fatigue using the method described in Section 4.3.2, and the results of the evaluation demonstrate that the number of design thermal cycles (7000) will not be exceeded in 60 years of plant operation. Therefore, the analyses associated with ANSI B31.1 piping fatigue have been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(I).

The staff finds the applicant's response to RAI 3.5-1 reasonable and acceptable because it provides an explanation that the main steam, feedwater, and AFW components in the SPCS are adequately managed for cumulative fatigue damage.

3.4.2.2.2 Loss of Material Due to General, Pitting, and Crevice Corrosion

The GALL Report recommends further evaluation of programs to manage loss of material due to general, pitting, and crevice corrosion of carbon steel piping and fittings, valve bodies and bonnets, pump casings, pump suction and discharge lines, tanks, tubesheets, channel heads, and shells (except for main steam system components), and for loss of material due to crevice and pitting corrosion for stainless steel tanks and heat exchanger/cooler tubes. The GALL Report Water Chemistry Program relies on monitoring and control of water chemistry, based on the guidelines in EPRI TR-102134, "PWR Secondary Water Chemistry Guideline—Revision 3," May 1993, for secondary water chemistry in PWRs, to manage the effect of loss of material due to general (carbon steel only), pitting, or crevice corrosion. However, corrosion may occur at locations of stagnant flow conditions. Therefore, the GALL Report recommends that the effectiveness of the Water Chemistry Control Program be verified to ensure that corrosion is not occurring.

The applicant proposed a one-time inspection of select components and susceptible locations to ensure that corrosion is not occurring. The staff reviewed the applicant's proposed program to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation. The staff verified that the applicant's selection of susceptible locations is based on severity of conditions, time of service, and lowest design margin. The staff also verified that the proposed inspection would be performed using techniques similar to ASME Code and ASTM standards.

In LRA Table 3.5-1, Item 2, the applicant stated that piping and fittings, valve bodies and bonnets, pump casings, tanks, tubes, tubesheets, channel head, and shell (except in main steam system) shall be managed for the aging effect of loss of material due to general (carbon steel only), pitting, and crevice corrosion using the Water Chemistry Control Program, but the Periodic Surveillance and Preventive Maintenance program will be used in lieu of the One-Time Inspection Program to verify that corrosion is not occurring. The staff's position is that corrosion may occur at locations of stagnation flow conditions and that a one-time inspection of select components and susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.
The Periodic Surveillance and Preventive Maintenance Program does not contain specific details of how this inspection will be performed. The staff issued RAI 3.5-2 asking the applicant to explain, for the components listed in LRA Table 3.5-1, Item 2, how the applicant's Periodic Surveillance and Preventive Maintenance Program inspects the piping internals to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation. The RAI also asked the applicant to state whether the selection of susceptible locations for one-time inspection locations is based on severity of conditions, time of service, and lowest design margin as recommended by NUREG-1801, AMP XI-M32.

In its response, by letter dated June 10, 2003, the applicant stated the following:

> Table 3.5-1, item 2 refers to components in secondary treated water environments in steam and power conversion systems, which at Ginna Station include main and auxiliary steam, feedwater and condensate, auxiliary feedwater and turbine-generator and supporting systems. The component types linked to item 2 include condensing chambers, pipe, valve bodies, flow elements, pump casings, tanks, controllers, governors, and trap housings. Portions of the feedwater and condensate and auxiliary feedwater systems contain legs of piping and valves exposed to stagnant secondary treated water. Several check valves in these stagnant legs are periodically disassembled and inspected under the periodic surveillance and preventive maintenance program. Plant maintenance procedures which implement these inspections will be enhanced to provide explicit guidance for detection of aging effects. Any condition requiring engineering evaluation will be addressed in accordance with the Ginna Station Corrective Action program. In addition, an engineering review of piping and components in these stagnant legs will be performed to evaluate components inspected under the periodic surveillance and preventive maintenance program for severity of operating conditions, time of service and design margin. Components with the longest time in service, lowest design margin, and most severe operating condition will be included in the periodic surveillance and preventive maintenance program.

The staff finds the applicant's response to RAI 3.5-2 reasonable and acceptable because the Periodic Surveillance and Preventive Maintenance Program provides adequate criteria to verify the effectiveness of the Water Chemistry Program.

On the basis of its review, the staff finds that the applicant appropriately evaluated AMR results involving management of loss of material due to general, pitting, and crevice corrosion for components in the SPCS, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with the GALL Report, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.3 Loss of Material Due to General, Pitting, and Crevice Corrosion, Microbiologically Influenced Corrosion, and Biofouling

The GALL Report recommends further evaluation of programs to manage loss of material due to general corrosion, pitting and crevice corrosion, MIC, and biofouling for carbon steel piping and fittings for untreated water from the backup water supply in the auxiliary feedwater system.

Loss of material due to general corrosion, pitting and crevice corrosion, MIC, and biofouling could occur in carbon steel piping and fittings for untreated water from the backup water supply in the AFW system. In LRA Table 3.5-1, Item 3, the applicant stated, "the combination of component, materials and environments identified in Item VIII.G.1-d [of the GALL Report] are evaluated in the service water system. The service water system components are reviewed under NUREG-1801, Chapter VII (Auxiliary Systems), Section C1." Based on this statement, the staff could not make a reasonable assurance finding that aging effects in the AFW piping connected to the backup water supply are adequately managed. The staff issued RAI 3.5-3 requesting the applicant to describe any specific AFW system components exposed to untreated water from the backup water supply and to describe the plant-specific AMP used to manage the loss of material for these components.

In its response, by letters dated May 13, 2003 and July 11, 2003, the applicant stated the following:

> There are no carbon steel components within the auxiliary feedwater system evaluation boundary normally exposed to untreated water. Untreated water can be aligned to the auxiliary feedwater system during an emergency as a suction source, but those interface components are evaluated within the service water system. The potential interface between service water and auxiliary feedwater is shown on Ginna Station drawing 33013-1237-LR at closed valves 4027 and 4020B (location D-2) and 4013 (location I-1). There are no locations in the boundary between the two systems where raw water could collect.

The staff finds the applicant's response to RAI 3.5-3 to be a reasonable and acceptable basis for concluding that no carbon steel components within the AFW system are exposed to raw water. Therefore, no aging management is required.

On the basis of its review, the staff concludes that the applicant provided reasonable assurance that the AFW piping is not exposed to untreated water and this aging effect is not applicable to Ginna Station.

3.4.2.2.4 Loss of Material Due to General Corrosion

The GALL Report recommends further evaluation of programs to manage loss of material due to general corrosion for external surfaces of all carbon steel SCs, including closure bolting exposed to operating temperatures less than 212 °F. Such corrosion may be due to air, moisture, or humidity. The staff reviewed the applicant's proposed program to ensure that an adequate program will be in place for the management of this aging effect.

In LRA Table 3.5-1, Item 5 credits the Systems Monitoring Program with managing the loss of material for the external surface of carbon steel components and states that it is "consistent with NUREG-1801 [GALL]." Since the GALL Report does not contain an approved AMP for loss of material due to general corrosion on the external surfaces of carbon steel components, the staff issued RAI 3.5-5 requesting the applicant to explain how the Systems Monitoring Program is considered to be consistent with the GALL Report.

In its response, by letter dated May 13, 2003, the applicant stated the following:

> Table 3.5-1 is based on the table in the steam and power conversion section of NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants." The table indicates that a plant specific aging management program is appropriate and that program requires further evaluation. Section 3.5 of the LRA describes the criterion applied by the licensee in determining if a NUREG-1800 line number is considered consistent with the GALL Report. In the final step of that process the programs credited in the GALL Report for managing an aging effect are compared to the programs invoked in Ginna Station plant evaluations. If, using good engineering judgement, it could be reasonably concluded that the plant evaluation is in agreement with the GALL Report evaluation, a line number was considered consistent with the GALL Report. In this case, although the aging management program invoked is plant specific, that program will comprise the 10 elements of a program as required by Appendix A of the GALL Report. Thus, because the program will detect loss of material on external surfaces of carbon steel components, and the program will be consistent with the required program elements, the applicant concluded that the systems monitoring program is consistent with the guidance of the GALL Report.

The staff finds the applicant's response to RAI 3.5-5 reasonable and acceptable because it explains the applicant's conclusion for stating that the Systems Monitoring Program is consistent with the GALL Report for managing loss of material due to general corrosion for external surfaces of SPCS carbon steel structures and components.

On the basis of its review, the staff finds that the applicant appropriately evaluated AMR results involving management of the loss of material due to general corrosion for components in the SPCS, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with the GALL Report, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.5 Loss of Material Due to General, Pitting, and Crevice Corrosion and Microbiologically Induced Corrosion

The GALL Report recommends further evaluation of programs to manage the loss of material due to general corrosion (carbon steel only), pitting and crevice corrosion, and MIC, for stainless steel and carbon steel shells, tubes, and tubesheets within the bearing oil coolers (for steam turbine pumps) in the AFW system. Such corrosion may be due to water contamination that affects the quality of the lubricating oil in the bearing oil coolers. The staff reviewed the applicant's proposed program to ensure that an adequate program will be in place for the management of the aging effects.

Section 3.4.2.4.5.1 presents the for staff evaluation describing how the Periodic Surveillance and Preventive Maintenance Program will manage the aging effects for the loss of material due to general corrosion (carbon steel only), pitting and crevice corrosion, and MIC in stainless steel and carbon steel shells, tubes, and tubesheets within the bearing oil coolers (for steam turbine pumps) in the AFW system.

In LRA Table 3.5-1, Item 4, the applicant stated that other components, such as accumulators, filter housing, orifices, piping, speed increasers, tanks, and valve bodies have been included in this line item at Ginna Station. Although these specific component types were not included in the GALL Report section, the applicant stated that the material, environment, aging effect/mechanism, and AMP for these components are consistent with the GALL Report. The staff considers it acceptable for the applicant to include these components in this line item and credit the Periodic Surveillance and Preventive Maintenance Program with managing all applicable aging effects, since the material, environment, aging effect/mechanism, and AMP for these components are similar to those components acceptable in the GALL Report.

On the basis of its review, the staff finds that the applicant appropriately evaluated AMR results involving management of the loss of material due to general, pitting, and crevice corrosion and MIC for components in the SPCS, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with the GALL Report, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.6 Conclusions

The staff has reviewed the applicant’s evaluation of the issues for which GALL recommends further evaluation for components in the SPCS. On the basis of its review, the staff finds that the applicant has provided sufficient information to demonstrate that the issues for which the GALL Report recommends further evaluation have been adequately addressed and that there is reasonable assurance that the subject aging effects will be adequately managed for the period of extended operation.

3.4.2.3 Aging Management Programs for Steam and Power Conversion Systems

In SER Section 3.4.2.1, the staff evaluated the applicant’s conformance with the aging management recommended by the GALL Report for the SPCS. In SER Section 3.4.2.2, the staff reviewed the applicant’s evaluation of the issues for which GALL recommends further evaluation. In this SER section, the staff presents its evaluation of the programs used by the applicant to manage the aging of the components in the SPCS.

The applicant credits seven AMPs with managing the aging effects associated with components in the SPCS. All seven of the AMPs are credited with managing aging for components in other system groups (common AMPs). The staff’s evaluation of the common AMPs credited with managing aging in SPCS components is provided in Section 3.0.3 of this SER. These common AMPs are listed below:

- Water Chemistry Control Program (3.0.3.1)
- Bolting Integrity Program (3.0.3.3)
- Boric Acid Corrosion Program (3.0.3.4)
- Flow-Accelerated Corrosion Program (3.0.3.6)
- One-Time Inspection Program (3.0.3.7)

- Periodic Surveillance and Preventive Maintenance Program (3.0.3.8)
- Systems Monitoring Program (3.0.3.11)

On the basis of its review, the staff finds that the applicant has properly identified the applicable aging effects and AMPs for the components in the SPCS at Ginna Station and that the components in the Ginna Station SPCS were correctly evaluated in the applicant's AMR and will be adequately managed during the period of extended operation.

3.4.2.3.1 There are no plant-specific AMPs for the SPCS.

3.4.2.4 Aging Management of Plant-Specific Components

The following sections provide the results of the staff's evaluation of the adequacy of aging management for SPCS components.

3.4.2.4.1 Main and Auxiliary Steam System

3.4.2.4.1.1 <u>Summary of Technical Information in the Application</u>. The AMR results for the main and auxiliary steam system are presented in Tables 3.4-1 and 3.4-2 of the LRA. The applicant used the GALL Report format to present its AMR of main and auxiliary steam system components in LRA Table 3.4-1. In LRA Table 3.4-2, the applicant identified the component group designation along with its (1) material, (2) environment, (3) aging effect(s), and (4) AMP(s).

As described in Section 2.3.4.1 of the LRA, the main and auxiliary steam system provides heat removal from the reactor coolant during normal, accident, and post-accident conditions. During off-normal conditions, the system provides emergency heat removal from the RCS using secondary heat removal capabilities. Some nonsafety-related portions of piping in the system have failure modes which could prevent the satisfactory accomplishment of safety-related functions (high-energy line breaks). The system is also credited with safe shutdown following station blackout events and some fire events and contains components that are part of the Environmental Qualification Program. Selected safety valve discharge vent piping is considered nonsafety equipment whose failure could affect the safety function due to its importance in directing steam flow out of a safety-related area. The conversion of the heat produced in the reactor to electrical energy is evaluated in the turbine generator system.

The principal components of the main steam portion of the system include the secondary side of two steam generators, where the main steam lines begin. Each steam line has a flow restrictor, four main steam safety valves, an atmospheric dump valve, and a steam admission valve to the turbine-driven auxiliary feedwater pump (TDAFW). The two steam lines join together in the intermediate building prior to entering the turbine building. Each steam line is also equipped with a fast-closing main steam isolation valve (MSIV) and a main steam nonreturn check valve. These valves prevent reverse flow in the steam lines that would result from an upstream steam line break, or they isolate any downstream steam line break at the common header. The atmospheric relief valves (ARVs) have two functions. They offer overpressure protection to the steam generator at a setpoint below the main steam safety valve (MSSV) setpoints and can be used to maintain no-load T_{avg} or perform a plant cooldown in the event the steam dump to the condenser is not available.

The principal components of the auxiliary steam portion of the system include the piping valves and tanks in the extraction steam and steam generator blowdown subsystems. In extraction steam, five stages of extraction are provided (two from the high-pressure turbine, one of which is the exhaust, and three from the low-pressure turbines). There are also two steam dump lines with four relief valves each to the condenser.

Continuous steam generator blowdown is used to reduce the quantities of solids that accumulate in the steam generators as a result of the boiling process. The blowdown recovery system is used to recover both the blowdown water and heat. Each steam generator has a blowdown header located at the bottom of the shell side just above the tubesheet. Both steam generators are equipped with independent blowdown piping from the connecting steam generator nozzles to a flash tank.
The piping transports the removed fluid and entrapped debris away from the steam generator, through containment penetrations, to a common flash tank in the turbine building basement. Flashed steam is vented from the flash tank to low-pressure feedwater heater 3A for heat recovery. The vented steam condenses in the feedwater heater and returns to the condenser through the feedwater heater drain system. The remaining condensate in the blowdown flash tank is drained directly to condenser 1B through a level control valve.

Aging Effects

Tables 3.4-1and 3.4-2 of the LRA identify the following applicable aging effects for the main and auxiliary steam system:

- cumulative fatigue damage of carbon steel components in steam and treated water environments

- loss of material due to general, pitting, and crevice corrosion of carbon and stainless steel components in steam and treated water environments

- loss of material due to general corrosion of carbon and low-alloy steel components (external surfaces) in air, moisture, and humidity environments

- wall thinning due to flow-accelerated corrosion of carbon steel components in steam and treated water environments

- loss of material due to general corrosion and crack initiation and growth due to cyclic loading, and loss of preload due to stress relaxation of closure bolting

- loss of material due to boric acid corrosion of carbon steel components (external surfaces) in air, leaking, and dripping chemically treated borated water environments

- loss of material and loss of heat transfer of cast iron heat exchangers in raw water environments

- loss of material of copper alloy, aluminum, and cast iron components in oil and fuel oil environments

- change in material properties and cracking of neoprene components in indoor air environments

- loss of material of carbon and low-alloy components in a air and gas (wetted) less than 140 °F environment

- loss of material of copper alloy (zinc less than 15 percent) components in treated water environments

- cracking due to stress-corrosion cracking of stainless steel components in treated water environments

Aging Management Programs

The following AMPs are utilized to manage aging effects to the main and auxiliary steam system:

- Periodic Surveillance and Preventive Maintenance Program
- Systems Monitoring Program
- Water Chemistry Control Program
- Flow-Accelerated Corrosion Program
- Bolting Integrity Program
- Boric Acid Corrosion Program
- One-Time Inspection Program

A description of these AMPs is provided in Appendix B to the LRA. The applicant concluded that the effects of aging associated with the components of the main and auxiliary steam system will be adequately managed by these AMPs such that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.4.2.4.1.2 Staff Evaluation. In addition to Section 3.4 of the LRA, the staff reviewed the pertinent information provided in Section 2.3.4, "Steam and Power Conversion Systems," and the applicable AMP descriptions provided in Appendix B to the LRA to determine whether the aging effects for the main and auxiliary steam system have been properly identified and will be adequately managed during 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 of the main and auxiliary steam system components at Ginna 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 appropriateness of the AMPs that are credited with managing the identified aging effects for the main and auxiliary steam SSCs.

Aging Effects

The component groups identified in LRA Table 2.3.4-1 for the main and auxiliary steam system are (1) condensing chamber, (2) converter, (3) carbon steel components, (4) fasteners (bolting), (5) flow element, (6) operator, (7) pipe, (8) positioner, (9) pressure relay, (10) screen, and (11) valve body (includes bonnet).

Aging Management Programs

The following AMPs are utilized to manage aging effects to the main and auxiliary steam system:

- Periodic Surveillance and Preventive Maintenance Program
- Systems Monitoring Program
- Flow-Accelerated Corrosion Program
- Water Chemistry Program
- Boric Acid Corrosion Program
- Bolting Integrity Program
- One-Time Inspection Program

These AMPs are credited with managing the aging of several components in different structures and systems and, therefore, are considered common AMPs. The staff review of the common AMPs is in Section 3.0.3 of this SER.

After evaluating the applicant's AMR for each of the main and auxiliary steam components, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects. For those components identified in Table 3.4-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in Tables 3.4-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effects.

The following generic RAI evaluations are applicable to main and auxiliary steam system components:

(1) Section 3.4.2.4.5.3 for evaluation of valve bonnets
(2) Section 3.4.2.4.5.6 for evaluation of flow elements

3.4.2.4.1.3 Conclusion. The staff has reviewed the information in Sections 2.3.4.1 and 3.4 of the LRA, as well as the applicable AMP descriptions in Appendix B to the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the components in the main and auxiliary steam system will be adequately managed so that there is reasonable assurance that these components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.4.2.4.2 Feedwater and Condensate System

3.4.2.4.2.1 Summary of Technical Information in the Application. The AMR results for the feedwater and condensate system are presented in Tables 3.4-1 and 3.4-2 of the LRA. The applicant used the GALL Report format to present its AMR of the feedwater and condensate system components in LRA Table 3.4-1. In LRA Table 3.4-2, the applicant identified the component group designation along with its (1) material, (2) environment, (3) aging effect(s), and (4) AMP(s).

As described in Section 2.3.4.2 of the LRA, the feedwater and condensate system functions to condense the steam exhausted from the low-pressure turbines, collect and store this condensate, and then send it back to the steam generator for reuse. Components within the system are used to provide emergency heat removal from the reactor coolant system using secondary heat removal capability. The engineered safety features actuation system (ESFAS) provides actuation signals for feedwater isolation. Portions of the main feedwater piping systems in the intermediate building of the turbine building have failure modes and effects that could prevent the satisfactory accomplishment of a safety-related function (high energy line breaks). The feedwater lines are equipped with a nonreturn valve and an isolation valve in each line. The nonreturn valve is the boundary between seismic Category I and nonseismic feedwater piping and prevents the steam generator from blowing back through the feedwater line if damage occurs to the nonseismic portion. Components within the system perform functions used to mitigate anticipated transients without scram (ATWS) and components that are part of the environmental qualification program.

The principal components of the feedwater and condensate system are the feedwater and condensate pumps, the feedwater regulating and bypass valves, feedwater heaters, and the essential piping and valves. The steam that leaves the exhaust of the low-pressure turbines enters the main condenser as saturated steam with low moisture content. This steam is condensed by the circulating water, which passes through the tubes of the condenser. The condensed steam collects in the condenser hotel from which the condensate pumps take suction. The condensate pumps increase the pressure of the water and provide suction head for the condensate booster pumps. The condensate booster pumps, in turn, provide sufficient suction head for the main feedwater pumps. Between the condensate pumps and the condensate booster pumps is the condensate demineralizer system, which maintains condensate water purity. The condensate booster pumps flow condensate through the condensate cooler, hydrogen coolers, air ejector condensers, gland steam condenser, and low-pressure heaters to the suction of the feedwater pumps. The feedwater pumps send feedwater through the high-pressure heaters to the steam generators via the feedwater regulating valves.

Aging Effects

LRA Tables 3.4-1 and 3.4-2 identify the following applicable aging effects for the feedwater and condensate system:

- cumulative fatigue damage of carbon steel components in a steam and treated water environment

- loss of material due to general, pitting, and crevice corrosion of carbon and stainless steel components in a steam and treated water environment

- loss of material due to general corrosion of carbon and low-alloy steel components (external surfaces) in an air, moisture, and humidity environment

- wall thinning due to flow-accelerated corrosion of carbon steel components in a steam and treated water environment

- loss of material due to general corrosion, crack initiation and growth due to cyclic loading, and loss of preload due to stress relaxation of closure bolting

- loss of material due to boric acid corrosion of carbon steel components (external surfaces) in an air, leaking, and dripping chemically treated borated water environment

- cracking due to stress-corrosion cracking of stainless steel components in a treated water environment

Aging Management Programs

The following AMPs are utilized to manage aging effects to the feedwater and condensate system:

- Periodic Surveillance and Preventive Maintenance Program
- Systems Monitoring Program
- Flow-Accelerated Corrosion Program
- Water Chemistry Program
- Boric Acid Corrosion Program
- Bolting Integrity Program
- One-Time Inspection Program

A description of these AMPs is provided in Appendix B to the LRA. The applicant concluded that the effects of aging associated with the components of the feedwater and condensate system will be adequately managed by these AMPs such that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.4.2.4.2.2 Staff Evaluation. In addition to Section 3.4 of the LRA, the staff reviewed the pertinent information provided in Section 2.3.4, "Steam and Power Conversion Systems," and the applicable AMP descriptions provided in Appendix B to the LRA to determine whether the aging effects for the feedwater and condensate system components have been properly identified and will be adequately managed during 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 of the feedwater and condensate system components at Ginna Station. The staff's evaluation included a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects. In addition, the staff evaluated the appropriateness of the AMPs that are credited with managing the identified aging effects for the feedwater and condensate system components.

Aging Effects

The component groups identified in LRA Table 2.3.4-2 for the feedwater and condensate system are (1) condensing chamber, (2) carbon steel components, (3) fasteners (bolting), (4) flow elements, (5) pipe, (6) temperature element, and (7) valve body (includes bonnet).

Aging Management Programs

The following AMPs are utilized to manage aging effects to the feedwater and condensate system:

- Periodic Surveillance and Preventive Maintenance Program
- Systems Monitoring Program
- Flow-Accelerated Corrosion Program
- Water Chemistry Program
- Boric Acid Corrosion Program
- Bolting Integrity Program
- One-Time Inspection Program

Each of the above AMPs are credited with managing the aging of several components in different structures and systems and, therefore, are considered common AMPs. The staff's review of these common AMPs is summarized in Section 3.0.3 of this SER.

After evaluating the applicant's AMR for each of the feedwater and condensate system components, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects. For those components identified in Table 3.4-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in Tables 3.4-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effects.

The following two generic RAI evaluations are applicable to the feedwater and condensate system components:

(1) Section 3.4.2.4.5.2 for evaluation of components in an open-cycle cooling water environment

(2) Section 3.4.2.4.5.3 for evaluation of valve bonnets

3.4.2.4.2.3 Conclusions. The staff has reviewed the information in Sections 2.3.4.2 and 3.4 of the LRA, as well as the applicable AMP descriptions in Appendix B to the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the components in the feedwater and condensate system will be adequately managed so that there is reasonable assurance that these components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.4.2.4.3 Auxiliary Feedwater System

3.4.2.4.3.1 Summary of Technical Information in the Application. The AMR results for the auxiliary feedwater system are presented in Tables 3.4-1 and 3.4-2 of the LRA. The applicant used the GALL Report format to present its AMR of the auxiliary feedwater system components in LRA Table 3.4-1. In LRA Table 3.4-2, the applicant identified the component group designation along with its (1) material, (2) environment, (3) aging effect(s), and (4) AMP(s).

As described in Section 2.3.4.3 of the LRA, the auxiliary feedwater system is designed to maintain steam generator water inventory when the normal feedwater system is not available. During accident and post-accident conditions, the auxiliary feedwater system supplies feedwater to the steam generators to provide emergency heat removal from the reactor coolant system using secondary heat removal capability (atmosphere or main condenser). The auxiliary feedwater system is also credited for use in mitigating ATWS, safe shutdown following a station blackout event, and some fires.

The principal components of the auxiliary feedwater system are electric motor-driven and steam turbine-driven feedwater pumps, the turbine-driven auxiliary feedwater (TDAFW) pump oil system, and the essential piping and valves. The preferred auxiliary feedwater system is divided into two independent trains. There are two motor-driven pumps powered from separate, redundant 480-V safeguards emergency buses which can receive power from either onsite or offsite sources. Each motor-driven pump can provide 100 percent of the preferred auxiliary feedwater system flow required for decay heat removal and can be cross-connected to provide flow to either steam generator. There is also a turbine-driven pump which can receive motive steam from each steam line and provide flow to either or both steam generators. This turbine-driven pump provides 200 percent of the flow required for decay heat removal.

A standby auxiliary feedwater (SAFW) system provides flow in case the preferred auxiliary feedwater system pumps are inoperable (e.g., a high-energy line break event could render inoperable the three preferred auxiliary feedwater pumps). The SAFW system uses two motor-driven pumps that can be aligned to separate service water (SW) system loops. The SAFW system has the same features as the preferred auxiliary feedwater system pumps with regard to functional capability and power supply separation. The system is manually actuated from the control room.

The condensate storage tanks are the normal (preferred) suction source for delivery of cooling water to the steam generators. The safety-related supply is from the plant service water system with the fire water system as a backup source.

Aging Effects

LRA Tables 3.4-1and 3.4-2 identify the following applicable aging effects for the auxiliary feedwater system:

- cumulative fatigue damage of carbon steel components in a steam and treated water environment

- loss of material due to general, pitting, and crevice corrosion of carbon and stainless steel components in a steam and treated water environment

- loss of material due to general (carbon steel only), pitting, and crevice corrosion and MIC of carbon and stainless steel components in a lubricating oil environment (possibly contaminated with water)

- loss of material due to general corrosion of carbon and low-alloy steel components (external surfaces) in an air, moisture, and humidity environment

- wall thinning due to flow-accelerated corrosion of carbon steel components in a steam and treated water environment

- loss of material due to general corrosion, crack initiation and growth due to cyclic loading, and loss of preload due to stress relaxation of closure bolting

- loss of material due to general, pitting, and crevice corrosion, MIC, and biofouling; buildup of deposit due to biofouling of carbon steel components in a raw water environment

- loss of material due to boric acid corrosion of carbon steel components (external surfaces) in an air, leaking, and dripping chemically treated borated water environment

- loss of material and loss of heat transfer of cast iron heat exchangers in a raw water environment

- loss of material of copper alloy, aluminum, and cast iron components in an oil and fuel oil environment

- loss of heat transfer of cast iron heat exchangers in an oil and fuel oil environment

- change in material properties and cracking of neoprene components in an indoor air environment

- loss of material of copper alloy (zinc less than 15 percent) components in a treated water environment

- loss of material of copper alloy (zinc less than 15 percent) components in an oil and fuel oil environment

- cracking due to stress-corrosion cracking of stainless steel components in a treated water environment

Aging Management Programs

The following AMPs are utilized to manage aging effects to the auxiliary feedwater system:

- Periodic Surveillance and Preventive Maintenance Program
- Systems Monitoring Program
- Flow-Accelerated Corrosion Program
- Water Chemistry Program
- Boric Acid Corrosion Program
- Bolting Integrity Program
- One-Time Inspection Program

A description of these AMPs is provided in Appendix B to the LRA. The applicant concluded that the effects of aging associated with the components of the auxiliary feedwater system will be adequately managed by these AMPs such that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.4.2.4.3.2 Staff Evaluation. In addition to Section 3.4 of the LRA, the staff reviewed the pertinent information provided in Section 2.3.4, "Steam and Power Conversion Systems," and the applicable AMP descriptions provided in Appendix B to the LRA to determine whether the aging effects for the auxiliary feedwater system components have been properly identified and will be adequately managed during 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 of the auxiliary feedwater system components at Ginna Station. The staff's evaluation included 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 appropriateness of the AMPs that are credited with managing the identified aging effects for the auxiliary feedwater system components.

Aging Effects

The component groups identified in LRA Table 2.3.4-3 for the auxiliary feedwater system are (1) accumulator, (2) controller, (3) cooler, (4) carbon steel components, (5) fasteners (bolting), (6) filter housing, (7) flow element, (8) governor, (9) heat exchanger, (10) level glass, (11) orifice, (12) pipe, (13) pump casing, (14) speed increaser, (15) tank, (16) trap housing, and (17) valve body (includes bonnet).

Aging Management Programs

The following AMPs are utilized to manage aging effects to the auxiliary feedwater system:

- Periodic Surveillance and Preventive Maintenance Program
- Systems Monitoring Program
- Flow-Accelerated Corrosion Program
- Water Chemistry Program
- Boric Acid Corrosion Program
- Bolting Integrity Program
- One-Time Inspection Program

Each of the above AMPs are credited with managing the aging of several components in different structures and systems and, therefore, are considered common AMPs. The staff's review of these common AMPs is summarized in Section 3.0.3 of this SER.

After evaluating the applicant's AMR for each of the auxiliary feedwater system components, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects. For those components identified in Table 3.4-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in Tables 3.4-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effects.

The following five generic RAI evaluations are applicable to the auxiliary feedwater system components:

(1) Section 3.4.2.4.5.1 for evaluation of components in an oil environment

(2) Sections 3.4.2.4.5.2 and 3.4.2.4.5.7 for evaluation of components in an open-cycle cooling water environment

(3) Section 3.4.2.4.5.3 for evaluation of valve bonnets

(4) Section 3.4.2.4.5.4 for evaluation of galvanic corrosion

(5) Section 3.4.2.4.5.6 for evaluation of flow elements

3.4.2.4.3.3 Conclusions. The staff reviewed the information in Sections 2.3.4.3 and 3.4 of the LRA, as well as the applicable AMP descriptions in Appendix B to the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the components in the auxiliary feedwater system will be adequately managed so that there is reasonable assurance that these components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.4.2.4.4 Turbine Generator and Supporting Systems

3.4.2.4.4.1 Summary of Technical Information in the Application. The AMR results for the turbine generator and supporting systems are presented in Tables 3.4-1 and 3.4-2 of the LRA.
The applicant used the GALL Report format to present its AMR of the components in the turbine generator and supporting systems in LRA Table 3.4-1. In LRA Table 3.4-2, the applicant identified the component group designation along with its (1) material, (2) environment, (3) aging effect(s), and (4) AMP(s).

As described in Section 2.3.4.4 of the LRA, the turbine generator and supporting systems function to convert the energy of the heat contained in the main steam into mechanical energy for use in turning the electric generator. These systems have no safety-related functions. Turbine first-stage pressure instruments provide a signal used in ATWS mitigation system actuation circuitry (AMSAC).

The plant subsystems bounded by the turbine generator and supporting systems include the high- and low-pressure turbine generator and controls, the main electrical generator, the electro-hydraulic control system, the turbine lube oil system, condenser air ejector and vacuum priming, generator hydrogen cooling, and generator seal oil systems.

The principal components of the turbine generator systems include turbines, the main generator, pumps, tanks, heat exchangers, and the essential piping and valves. The main turbine is made up of one high-pressure and two low-pressure turbines, all mounted on a common shaft. The steam flow path is first through the high-pressure turbine, then in a parallel path to the two low-pressure units via the four moisture separator reheaters. High-pressure steam is admitted to the high-pressure turbine through two stop and four governing control valves. These valves are controlled by the electrohydraulic control system. Turbine supervisory instrumentation is provided to monitor turbine vibration, eccentricity, and differential thermal expansion, as well as to provide alarms in the control room in the case of abnormal conditions.

The main turbine is supported by a number of auxiliary systems that improve the efficiency and safety of its operation. First and second stage air ejectors remove air and noncondensible gases from the condenser and maintain them under a vacuum, thereby improving efficiency of the main turbine by reducing the backpressure seen by the turbine exhaust. The gland sealing and exhaust applies steam to a labyrinth seal around the rotor shaft to preclude air in-leakage into the turbine casings and condenser and to prevent steam leakage into the turbine building. The vacuum priming system uses mechanical vacuum pumps to prevent air buildup in the condenser water boxes or tubes—a condition that would reduce condenser efficiency. The exhaust hood spray prevents overheating of the last stage, low-pressure blading under low steam flow conditions. The turbine lube oil system provides lubrication and cooling of the turbine bearings and supplies oil to the auto-stop header for turbine protection. It also provides backup oil to the seal oil system to prevent hydrogen leakage in the turbine building. A purification system is an adjunct to the turbine lube oil system to remove water and contaminants from the lube oil, as well as to provide storage space for makeup oil. The generator auxiliary systems are required to ensure that the main generator will operate at its maximum rated output safely and efficiently. This is accomplished by cooling the generator rotor, stator, exciter, main output bushings, and the isophase bus ducts. Pressurized hydrogen is circulated by the internal ventilation of the generator to remove heat produced in the rotor and stator. The hydrogen then transfers this heat to the hydrogen coolers which are supplied with cooling water from the condensate system. To prevent the escape of hydrogen along the generator shaft and out of the casing, a seal oil system is utilized. The air-side seal oil pump and the hydrogen-side, seal oil pump provide oil for sealing at a pressure higher than the generator hydrogen pressure. The main turbine lube oil system can provide a backup source of pressurized seal oil.

<u>Aging Effects</u>

LRA Tables 3.4-1 and 3.4-2 identify the following applicable aging effects for the turbine generator and supporting systems:

- cumulative fatigue damage of carbon steel components in a steam and treated water environment

- loss of material due to general, pitting, and crevice corrosion of carbon and stainless steel components in a steam and treated water environment

- loss of material due to general corrosion of carbon and low-alloy steel components (external surfaces) in an air, moisture, and humidity environment

- wall thinning due to flow-accelerated corrosion of carbon steel components in a steam and treated water environment

- cracking due to stress-corrosion cracking of stainless steel components in a treated water environment

Aging Management Programs

The following AMPs are utilized to manage aging effects to the turbine generator and supporting systems:

- Periodic Surveillance and Preventive Maintenance Program
- Systems Monitoring Program
- Flow-Accelerated Corrosion Program
- Water Chemistry Program

A description of these AMPs is provided in Appendix B to the LRA. The applicant concluded that the effects of aging associated with the components of the turbine generator and supporting systems will be adequately managed by these AMPs such that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.4.2.4.4.2 Staff Evaluation. In addition to Section 3.4 of the LRA, the staff reviewed the pertinent information provided in Section 2.3.4, “Steam and Power Conversion Systems,” and the applicable AMP descriptions provided in Appendix B to the LRA to determine whether the aging effects for the components of the turbine generator and supporting systems have been properly identified and will be adequately managed during 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 of the components of the turbine generator and supporting systems at Ginna Station. The staff’s evaluation included a review of the aging effects considered and the basis for the applicant’s elimination of certain aging effects. In addition, the staff evaluated the appropriateness of the AMPs that are credited with managing the identified aging effects for the turbine generator and supporting systems components.

Aging Effects

The component groups identified in LRA Table 2.3.4-4 for the turbine generator and supporting systems are (1) pipe and (2) valve body (includes bonnet).

Aging Management Programs

The following AMPs are utilized to manage aging effects to the turbine generator and supporting systems:

- Periodic Surveillance and Preventive Maintenance Program
- Systems Monitoring Program
- Flow-Accelerated Corrosion Program
- Water Chemistry Program

Each of the above AMPs are credited with managing the aging of several components in different structures and systems and, therefore, are considered common AMPs. The staff's review of these common AMPs is summarized in Section 3.0.3 of this SER.

After evaluating the applicant's AMR for each of the components of the turbine generator and supporting systems components, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects. For those components identified in Table 3.4-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in Tables 3.4-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effects.

The following generic RAI evaluations are applicable to turbine generator and supporting systems components:

(1) Section 3.4.2.4.5.3 for evaluation of valve bonnets
(2) Section 3.4.2.4.5.5 for evaluation of fasteners

3.4.2.4.4.3 Conclusions. The staff reviewed the information in Sections 2.3.4.4 and 3.4 of the LRA, as well as the applicable AMP descriptions in Appendix B to the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the components in the turbine generator and supporting systems will be adequately managed so that there is reasonable assurance that these components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.4.2.4.5 Generic RAI Issues

3.4.2.4.5.1 Use of the Periodic Surveillance and Preventive Maintenance Program to Manage Aging Effects for Components in an Oil Environment. For the steam and power conversion systems, the Periodic Surveillance and Preventive Maintenance Program is credited with managing several aging effects, although it does not contain details of how these aging effects will be managed. The staff issued RAI 3.5-4 requesting the applicant to explain how the Periodic Surveillance and Preventive Maintenance Program will manage the aging effects for (1) LRA Table 3.5-1, Item 4 for loss of material due to general corrosion (carbon steel only), pitting and crevice corrosion, and MIC that could occur in stainless steel and carbon steel shells, tubes, and tubesheets within the bearing oil coolers (for steam turbine pumps) in the AFW system, (2) LRA Table 3.5.2, Items 18 and 19 for loss of heat transfer and loss of material for heat exchangers in an oil and fuel environment, and (3) LRA Table 3.5-2, Items 23, 47, and 64 for loss of material in level glass, pump casing, and valve body components in an oil and fuel environment.

Also, Table 3.5-1, Item 4, concerning loss of material within the bearing oil coolers, states, in the discussion column, "Consistent with NUREG-1801. The Periodic Surveillance and Preventive Maintenance Program is credited with managing all applicable aging effects." Since NUREG-1801 does not contain an approved AMP for loss of material within the bearing oil coolers, the staff requested the applicant to explain why the Periodic Surveillance and Preventive Maintenance Program is considered to be consistent with the GALL Report (NUREG-1801).

In its response, by letter dated June 10, 2003, the applicant stated the following:

> 1) Table 3.5-1, item 4 refers to the stainless steel lube oil coolers for the motor-driven and turbine-driven auxiliary feedwater pumps. These coolers are shell and tube heat exchangers. The coolers are periodically cleaned and inspected under the periodic surveillance and preventive maintenance program. Service water flows through the tube side of these units, and lubricating oil through the shell side. The tubes of these units are inspected by eddy current testing, which is a volumetric technique and is credited for managing aging effects such as loss of material due to pitting and crevice corrosion and MIC on both the ID and OD of the tubes.
>
> 2) Table 3.5-2, item 18 and 19 refer to the lubricating oil side of the outboard bearing lube oil coolers for the motor-driven and turbine-driven auxiliary feedwater pumps. It should be noted that the lubricating oil environment to which the cast iron housing is exposed is a benign environment and would not be expected to support corrosion of the bearing housing. The lubricating oil contained in these coolers is periodically sampled and analyzed as directed by the periodic surveillance and preventive maintenance program. The analysis includes a full spectrum of elements which has been monitored and trended over a 10 year period. Any adverse trend in the iron content could be attributed to wear particulate or corrosion products. Such a condition would be addressed under the Ginna Station Corrective Action program and would include a determination of the origin of the iron concentration.
>
> 3) Table 3.5-2, items 23, 47, and 64 refer to aluminum level glass housing, cast iron pump casing, and copper alloy valve body components exposed to a lubricating oil environment. As discussed in item 2 above, the periodic surveillance and preventive maintenance program includes analysis of the lubricating oil to which these components are exposed. The analytical results provide levels of aluminum, iron and copper present in the oil. Any adverse trend in the iron content could be attributed to wear particulate or corrosion products. Any adverse trend in aluminum or copper levels would be attributed to corrosion products. These conditions would be addressed under the Ginna Station Corrective Action program and would include a determination of the origin of the element exhibiting the adverse trend.
>
> 4) The aging management program referenced in Table 3.5-1 item 4 is plant specific. The periodic surveillance and preventive maintenance program is a plant specific program at Ginna Station and therefore the aging management program credited for managing the effects of aging for components included in item 4 is consistent with NUREG 1801. All of the program attributes have been compared with the program elements in NUREG 1800, Appendix A and found to be consistent with the requirements.

3.4.2.4.5.1.1 <u>Staff Evaluation of RAI 3.5-4</u>. The staff finds that the applicant's response to RAI 3.5-4 provides an acceptable explanation as to how the Periodic Surveillance and Preventive Maintenance Program manages aging effects for components in an oil environment. Therefore, the staff finds that the aging effects for components in an oil environment will be managed by the Periodic Surveillance and Preventive Maintenance Program.

3.4.2.4.5.2 Use of the Periodic Surveillance and Preventive Maintenance Program to Manage Aging Effects for Components in an Open-Cycle Cooling Water Environment. Loss of material due to general corrosion (carbon steel only), pitting and crevice corrosion, MIC, and biofouling, as well as buildup of deposit due to biofouling, could occur in stainless steel and carbon steel heat exchangers and coolers/condensers serviced by the open-cycle cooling water system. Table 3.5-1, Item 9, concerning the loss of material in heat exchangers and coolers/condensers serviced by open-cycle cooling water, states, in the discussion column, "the periodic surveillance and preventive maintenance program will be credited with managing the applicable aging effects in lieu of the open-cycle cooling (service) water system program." The applicant's Periodic Surveillance and Preventive Maintenance Program does not specifically identify inspection of these heat exchangers and coolers/condensers serviced by the open-cycle cooling water system. The staff issued RAI 3.5-6 requesting the applicant to identify how the Periodic Surveillance and Preventive Maintenance Program will be used to manage loss of material due to general corrosion (carbon steel only), pitting and crevice corrosion, MIC, and biofouling, as well as buildup of deposit due to biofouling, in stainless steel and carbon steel heat exchangers and coolers/condensers serviced by the open-cycle cooling water system. The staff also requested the applicant to discuss whether the AMP relies on the recommendations of NRC GL 89-13 to ensure that the effects of aging on the open-cycle cooling water system will be managed for the extended period of operation.

In its response, by letter dated May 23, 2003, the applicant stated the following:

> The periodic surveillance and preventive maintenance program implements the inspections of heat exchangers at Ginna Station that are serviced by open cycle (service) water. The scope of the program now explicitly includes heat exchangers and the program attributes include appropriate references to eddy current inspections of tubing and visual inspections of channel heads. The open-cycle cooling water system program references the periodic surveillance and preventive maintenance program as the implementing program for these inspections. The open-cycle cooling water system program directs many other activities as well as periodic inspections, and is consistent with the recommendations of Generic Letter 89-13. Therefore, the effects of aging on the open-cycle cooling water system will be managed for the period of extended operation.

3.4.2.4.5.2.1 Staff Evaluation of RAI 3.5-6. The staff finds that the applicant's response to RAI 3.5-6 provides an acceptable explanation as to how the Periodic Surveillance and Preventive Maintenance Program implements the open-cycle cooling water program to manage aging effects for components in an open-cycle cooling water environment.

3.4.2.4.5.3 Valve Bonnets. LRA Tables 2.3.4-1, 2.3.4-2, 2.3.4-3, 2.3.4-4, 3.5-1, and 3.5-2 list "valve body" in the component column. The NRC position is that the aging effects identified in these tables, except for wall thinning due to flow-accelerated corrosion, are applicable to both the valve body and bonnet. The staff issued RAI 3.5-7 requesting the applicant to explain why the valve bonnets are not included with the valve bodies or to provide aging management for the bonnets.

In its response, by letter dated May 13, 2003, the applicant stated the following:

> Bonnets are a part of the body and are included in the LRA in Tables 3.5-1 and Table 3.5-2, under "valve body."

3.4.2.4.5.3.1 Staff Evaluation of RAI 3.5-7. The staff finds that the applicant's response to RAI 3.5-7 provides an acceptable explanation that valve bonnets are part of the valve body.

3.4.2.4.5.4 Galvanic Corrosion. Tables 3.5-1 and 3.5-2 of the LRA do not identify galvanic corrosion as an aging effect that requires management for the steam and power conversion systems. Galvanic corrosion could occur at bimetallic joints in a raw water environment where the water chemistry is not controlled. This condition normally exists for the raw water side of heat exchangers. The staff issued RAI 3.5-8 requesting the applicant to explain if conditions exist where steam and power conversion systems' piping or components at Ginna Station should be managed for galvanic corrosion. If conditions do exist, the applicant needed to explain how these components are managed for galvanic corrosion.

In its response, by letter dated May 23, 2003, the applicant stated the following:

> Loss of material due to galvanic corrosion was evaluated during the aging management review process as an applicable aging effect/mechanism. It is recognized that Tables 3.5-1 and 3.5-2 do not identify galvanic corrosion as an aging mechanism. Therefore, an engineering guidance document will be written directing inspections to evaluate galvanic corrosion at susceptible locations in raw water environments. These inspections will be performed under the one-time inspection program.
> The guidance document shall include acceptance criteria, guidance for evaluation of results, a requirement for follow-up inspections based on the initial inspection results if necessary, a requirement for initiation of an action report for any indication of degradation exceeding acceptance criteria and requiring engineering evaluation or resolution, and the time frame during which the components shall be inspected (note: all inspections will be completed before the period of extended operation).

Based on the applicant's response to RAI 3.5-8, the staff submitted the following question:

> As described in the GALL Report, the one-time inspection program is used to verify the effectiveness of an aging management program (AMP) and confirm the absence of an aging effect expected to occur very slowly or not at all. For example, the water chemistry program manages aging effects for piping internals and the one-time inspection program verifies effectiveness of the water chemistry AMP by confirming that unacceptable degradation is not occurring and the intended function will be maintained during the period of extended operation. In a raw water environment, galvanic corrosion is likely to occur; therefore, periodic inspections are more appropriate for managing these aging effects. Explain the basis for performing one-time inspections to manage galvanic corrosion in raw water or provide periodic inspections to manage this aging effect.

In its response, by letter dated July 11, 2003, the applicant stated the following:

> The severity of galvanic corrosion is directly related to the following factors: 1) the galvanic potential difference between the alloys in electrical contact; 2) the conductivity/corrosivity of the environment; and 3) the cathode-to-anode (noble/active member) surface area ratio. Raw water at Ginna Station is fresh Lake Ontario water and is not aggressive. Typical chloride levels are 20-25 ppm; sulfate levels are 25-30 ppm and the pH is near neutral. Based on these facts, as well as plant-specific operating experience, the raw water environment at Ginna Station would not be expected to support significant galvanic corrosion. As a result, inspections will be performed under the one-time inspection program to evaluate galvanic corrosion in "susceptible" components prior to the end of the current license period. If the results of these inspections indicate that degradation due to galvanic corrosion has occurred in any component, then a repetitive inspection task will be created under the periodic surveillance and preventive maintenance program and the component will be periodically inspected.

3.4.2.4.5.4.1 Staff Evaluation of RAI 3.5-8. The staff finds that the applicant's response to RAI 3.5-8 provides an acceptable explanation as to how galvanic corrosion is managed in a raw water environment.

3.4.2.4.5.5 Fasteners for Turbine Generator and Supporting Systems. Table 2.3.4-4 of the LRA for the turbine generator and supporting systems does not list fasteners in the component group column. The staff issued RAI 3.5-9 requesting the applicant to identify if there are any fasteners in these systems that require an AMR. Also, if it is determined that valve and bonnets are in scope of license renewal, the applicant needed to explain whether the body to bonnet fasteners require an AMR.

In its response, by letter dated May 23, 2003, the applicant stated the following:

> Fasteners should have been included in LRA Table 2.3.4-4. These fasteners, however, were evaluated in Table 3.5-1 line number (8), and Table 3.5-2 line numbers (7) and (8) for aging management.

3.4.2.4.5.5.1 Staff Evaluation of RAI 3.5-9. The staff finds that the applicant's response to RAI 3.5-9 provides an acceptable explanation that fasteners in the turbine generator and supporting systems are managed for aging in LRA Tables 3.5-1 and 3.5-2.

3.4.2.4.5.6 Use of the Water Chemistry and One-Time Inspection Programs to Manage Aging Effects for Flow Elements. In LRA Table 3.5-2, Items 38, 41, 72, 73, 74, and 75 identify aging management of valve bodies and piping for cracking due to SCC and loss of material using the Water Chemistry Program. For these items, the One-Time Inspection Program is identified to verify the effectiveness of the Water Chemistry Program. LRA Table 3.5-2, Items 15 and 16 identify aging management of flow elements for cracking due to SCC and loss of material using the Water Chemistry Program, but do not identify the One-Time Inspection Program to verify the effectiveness of the Water Chemistry Program. The staff issued RAI 3.5-10 requesting the applicant to explain why the One-Time Inspection Program is not used to verify the effectiveness of the Water Chemistry Program for the flow elements that have material and environment identical to the valve bodies and piping.

In its response, by letter dated May 23, 2003, the applicant stated the following:

> The water chemistry control program, as described in LRA section B2.1.37 relies on monitoring and control of water chemistry based on the EPRI guidelines in TR-105714 for primary systems chemistry and TR-102134 for secondary systems chemistry. For low-flow or stagnant portions of a system, a one-time inspection of selected components at susceptible locations provides verification of the effectiveness of the water chemistry control program. No verification inspections are required for intermediate and high flow regions.
>
> Therefore, the one-time inspection program is not listed in Table 3.5-2, items 15 and 16, for the stainless steel flow elements in a treated water secondary >120°F environment, since this is not stagnant or low flow. Table 3.5-2, conservatively shows the one-time inspection program for valve bodies and piping in the identical environment, however this is not a requirement based on the discussion of the water chemistry program defined in LRA Section B2.1.37.

3.4.2.4.5.6.1 Staff Evaluation of RAI 3.5-10. The staff finds that the applicant's response to RAI 3.5-10 provides an acceptable explanation as to why the One-Time Inspection Program is not used to verify of the effectiveness of the Water Chemistry Control Program for certain flow elements.

3.4.2.4.5.7 Use of the One-Time Inspection and Periodic Surveillance and Preventive Maintenance Programs to Manage Aging Effects for Components in an Open-Cycle Cooling Water Environment. In LRA Table 3.5.2, Items 20 and 21 identify the One-Time Inspection Program as managing loss of heat transfer and loss of material for heat exchangers in a raw water environment. The GALL Report AMP for managing these aging effects is the Open-Cycle Cooling Water System Program. The staff issued RAI 3.5-11 requesting the applicant to explain how the One-Time Inspection Program will manage these aging effects, and whether the AMP relies on the recommendations of NRC GL 89-13 to ensure that the effects of aging on the open-cycle cooling water system will be managed for the extended period of operation. The staff also noted that the use of the One-Time Inspection Program does not appear to be consistent with Table 3.5-1, Item 9, where the applicant identified its Periodic Surveillance and Preventive Maintenance Program to manage similar aging effects for heat exchangers in an open-cycle cooling water environment.

In its response, by letter dated May 23, 2003, the applicant stated the following:

> Items 20 and 21 in LRA Table 3.5-2 refer to the cast iron outboard bearing oil coolers for the two motor-driven and one turbine-driven auxiliary feedwater pumps. These coolers are of similar design to those on the safety injection pumps. These coolers consist of a cast iron chamber through which service water flows to provide cooling. Service water at Ginna Station is fresh Lake Ontario water and is not aggressive.
>
> A performance test is performed periodically on the safety injection pump outboard bearing coolers to verify service water flow. No evidence of reduction in flow has ever been detected. As a result of the excellent resistance of gray cast iron to service water at Ginna Station, aging effects would either not be expected to occur or would be expected to occur so slowly as to be essentially negligible. Therefore a one-time inspection of the outboard bearing coolers is appropriate to verify that the coolers will continue to perform their intended functions during the period of extended operation.
>
> LRA Table 3.5-1, item 9 refers to the lube oil coolers for the motor-driven and turbine driven auxiliary feedwater pumps. These coolers are stainless steel shell-and-tube heat exchangers that are cleaned and inspected periodically under the periodic surveillance and preventive maintenance program. Service water flows through the tube side of these units and lubricating oil through the shell side. Plant-specific operating experience has shown that these lube oil coolers are susceptible to tube-side fouling. Therefore these coolers are periodically cleaned and inspected as directed by the periodic surveillance and preventive maintenance program in support of the open-cycle cooling water system program which incorporates the recommendations of GL 89-13.

3.4.2.4.5.7.1 Staff Evaluation of RAI 3.5-11. The staff finds that the applicant's response to RAI 3.5-11 provides an acceptable explanation as to how the One-Time Inspection and Periodic Surveillance and Preventive Maintenance Programs manage aging effects for components in an open-cycle cooling water environment.

3.4.2.4.5.8 Use of the Periodic Surveillance and Preventive Maintenance Program to Manage Aging Effects for Atmospheric Relief Valve Tailpieces. A one-time inspection can be used to address concerns for the potentially long incubation period for certain aging effects on structures and components. There are cases in which either an aging effect is not expected to occur, but there is insufficient data to completely rule it out, or an aging effect is expected to progress very slowly. For these cases, the applicant needs to confirm (by one-time inspection) that either the aging effect is indeed not occurring, or the aging effect is occurring very slowly and is not affecting the component or structure intended function. Based on these guidelines, the staff issued RAI 3.5-12 requesting the applicant to provide operating experience to confirm that the aging effect is not expected to occur, or is expected to progress very slowly, for the piping identified in LRA Table 3.5-2, Item 29.

In its response, by letter dated May 23, 2003, the applicant stated the following:

> LRA Table 3.5-2, item 29 refers to the carbon steel tailpieces for the atmospheric relief valves. An inspection of these tailpieces will be performed to determine whether significant degradation has occurred. These components will subsequently be included in the periodic surveillance and preventive maintenance program. Table 3.5-2, item 29 should also have included the periodic surveillance and preventive maintenance program as an applicable aging management program.

3.4.2.4.5.8.1 Staff Evaluation of RAI 3.5-12. The staff finds that the applicant's response to RAI 3.5-12 provides an acceptable explanation as to how the Periodic Surveillance and Preventive Maintenance Program is used to manage aging effects for atmospheric relief valve tailpieces.

3.4.3 Evaluation Findings

On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and the AMPs credited with managing the aging effects for the steam and power conversion system, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation. The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement for Ginna provides an adequate program description of the AMPs credited with managing aging effects, as required by 10 CFR 54.21(d).

3.5 Containment, Structures, and Component Supports

This section addresses the applicant's AMR of structural components within the containment, other Class I structures, and component supports. The components that make up this group are described in the following SER sections:

- Containment (2.4.1)
- Auxiliary Building (2.4.2.1)
- Intermediate Building (2.4.2.2)
- Turbine Building (2.4.2.3)
- Diesel Building (2.4.2.4)
- Control Building (2.4.2.5)
- All Volatile Water Building (2.4.2.6)
- Screen House Building (2.4.2.7)
- Standby Auxiliary Feedwater Building (2.4.2.8)
- Service Building (2.4.2.9)
- Cable Tunnel (2.4.2.10)
- Essential Yard Structures (2.4.2.11)

- Component Supports (2.4.2.12)

As discussed in Section 3.0.1 of this SER, the structural components are included in one of two LRA tables. LRA Table 3.6-1 consists of the structural components that are evaluated in the GALL Report, and LRA Table 3.6-2 consists of the structural components that are not evaluated in the GALL Report.

3.5.1 Summary of Technical Information in the Application

In LRA Section 3.6, the applicant described its AMRs for the structural components within the containment, other Class I structures, and component supports at Ginna. The passive, long-lived components in these structures that are subject to an AMR are identified in LRA Tables 2.4.1 and 2.4.2.

The applicant's AMRs included an evaluation of plant-specific and industry operating experience. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify aging effects that require management. These reviews concluded that the aging effects requiring management, based on the Ginna operating experience, were consistent with the aging effects identified in GALL. The applicant's review of industry operating experience included a review of operating experience through 2002. The results of this review concluded that the aging effects requiring management, based on industry operating experience, were consistent with the aging effects identified in GALL. The applicant's ongoing review of plant-specific and industry-wide operating experience is conducted in accordance with the Ginna Operating Experience Program.

3.5.2 Staff Evaluation

In Section 3.6 of the LRA, the applicant described its AMR for the structural components within the containment, other Class I structures, and component supports at Ginna. The staff reviewed LRA Section 3.6 to determine whether the applicant had provided sufficient information to demonstrate that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the period of extended operation, in accordance with the requirements of 10 CFR 54.21(a)(3), for structures and structural components that are determined to be within the scope of license renewal and subject to an AMR.

The applicant referenced the GALL Report in its AMR. The staff has previously evaluated the adequacy of the aging management of structural components for license renewal, as documented in the GALL Report. Thus, the staff did not repeat its review of the items described in the GALL Report, except to ensure that the material presented in the LRA was applicable, and to verify that the applicant had identified the appropriate programs as described and evaluated in the GALL Report.

The staff evaluated those aging management issues recommended for further evaluation in the GALL Report, as well as the applicant's AMR for structural components not addressed in GALL. In addition, the staff evaluated the AMPs used by the applicant to manage the aging of structural components. Finally, the staff reviewed the structural components listed in LRA Section 2.4 to determine whether the applicant properly identified the applicable aging effects and the AMPs needed to adequately manage them.

Table 3.5-1 below provides a summary of the staff's evaluation of the components, aging effects/mechanisms, and AMPs listed in LRA Section 3.5 that are addressed in the GALL Report.

Table 3.5-1 Staff Evaluation for Ginna Structures and Structural Components in the GALL Report

Common Components of All Types of PWR and BWR Containment

Component Group	Aging Effect/Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Penetration sleeves, penetration bellows, and dissimilar metal welds	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA evaluated in accordance with 10 CFR 54.21(c)	TLAA (4.7.4)	Consistent with GALL. GALL recommends further evaluation (see Section 3.5.2.2.1.6 below)
Penetration sleeves, penetration bellows, and dissimilar metal welds	Cracking due to cyclic loading or crack initiation and growth due to SCC	Containment ISI and containment leak rate test	ASME Section XI, Subsections IWE and IWL Inservice Inspection Program (B2.1.3)	Consistent with GALL. GALL recommends further evaluation (see Section 3.5.2.2.1.7 below)
Penetration sleeves, penetration bellows, and dissimilar metal welds	Loss of material due to corrosion	Containment ISI and containment leak rate test	ASME Section XI, Subsections IWE and IWL Inservice Inspection Program (B2.1.3)	Consistent with GALL (see Section 3.5.2.1 below)
Personnel airlock and equipment hatch	Loss of material due to corrosion	Containment ISI and containment leak rate test	ASME Section XI, Subsections IWE and IWL Inservice Inspection Program (B2.1.3) and Periodic Surveillance and Preventive Maintenance Program (B2.1.23)	Consistent with GALL (see Section 3.5.2.1 below)
Personnel airlock and equipment hatch	Loss of leak tightness in closed position due to mechanical wear of locks, hinges, and closure mechanisms	Containment leak rate test and plant technical specifications	ASME Section XI, Subsections IWE and IWL Inservice Inspection Program (B2.1.3) and Periodic Surveillance and Preventive Maintenance Program (B2.1.23)	Consistent with GALL (see Section 3.5.2.1 below)
Seals, gaskets, and moisture barriers	Loss of sealant and leakage through containment due to deterioration of joint seals, gaskets, and moisture barriers	Containment ISI and containment leak rate test	ASME Section XI, Subsections IWE and IWL Inservice Inspection Program (B2.1.3) and Periodic Surveillance and Preventive Maintenance Program (B2.1.23)	Consistent with GALL (see Section 3.5.2.1 below)

PWR Concrete (Reinforced and Prestressed) and Steel Containment
BWR Concrete (Mark II and III) and Steel (Mark I, II, and III) Containment

Component Group	**Aging Effect/Mechanism**	**AMP in GALL Report**	**AMP in LRA**	**Staff Evaluation**
Concrete elements: foundation, walls, dome	Aging of accessible and inaccessible concrete areas due to leaching of calcium hydroxide, aggressive chemical attack, and corrosion of embedded steel	Containment ISI	ASME Section XI, Subsections IWE and IWL Inservice Inspection Program (B2.1.3)	Consistent with GALL. GALL recommends further evaluation (see Section 3.5.2.2.1.1 below)
Concrete elements: foundation	Cracks, distortion, and increases in component stress level due to settlement	Structures Monitoring	Structures Monitoring Program (B2.1.32)	Consistent with GALL. GALL recommends further evaluation (see Section 3.5.2.2.1.2 below)
Concrete elements: foundation	Reduction in foundation strength due to erosion of porous concrete subfoundation	Structures Monitoring	Structures Monitoring Program (B2.1.32)	Consistent with GALL. GALL recommends further evaluation (see Section 3.5.2.2.1.2 below)
Concrete elements: foundation, dome, and wall	Reduction of strength and modulus due to elevated temperature	Plant specific	ASME Section XI, Subsections IWE and IWL Inservice Inspection Program (B2.1.3)	Consistent with GALL. GALL recommends further evaluation (see Section 3.5.2.2.1.3 below)
Prestressed containment: tendons and anchorage components	Loss of prestress due to relaxation, shrinkage, creep, and elevated temperature	TLAA evaluated in accordance with 10 CFR 54.21(c)	TLAA (4.5)	Consistent with GALL. GALL recommends further evaluation (see Section 3.5.2.2.1.5 below)
Steel elements: liner plate and containment shell	Loss of material due to corrosion in accessible and inaccessible areas	Containment ISI and containment leak rate test	ASME Section XI, Subsections IWE and IWL Inservice Inspection Program (B2.1.3) and Boric Acid Corrosion Program (B2.1.6)	Consistent with GALL. GALL recommends further evaluation (see Section 3.5.2.2.1.4 below)
Steel elements: vent header, drywell head, torus, downcomers, and pool shell	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA evaluated in accordance with 10 CFR 54.21(c)	None	Not applicable to Ginna (BWR)
Steel elements: protected by coating	Loss of material due to corrosion in accessible areas only	Protective coating monitoring and maintenance	None	Protective coatings are not credited with managing the effects of aging at Ginna.

Component Group	Aging Effect/Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Prestressed containment: tendons and anchorage components	Loss of material due to corrosion of prestressing tendons and anchorage components	Containment ISI	ASME Section XI, Subsections IWE and IWL Inservice Inspection Program (B2.1.3), Structures Monitoring Program (B2.1.32), and Periodic Surveillance and Preventive Maintenance Program (B2.1.23)	Consistent with GALL (see Section 3.5.2.1 below)
Concrete elements: foundation, dome, and wall	Scaling, cracking, and spalling due to freeze-thaw; expansion and cracking due to reaction with aggregate	Containment ISI	ASME Section XI, Subsections IWE and IWL Inservice Inspection Program (B2.1.3)	Consistent with GALL (see Section 3.5.2.1 below)
Steel elements: vent line bellows, vent headers, downcomers	Cracking due to cyclic loads or crack initiation and growth due to SCC	Containment ISI and Containment leak rate test	None	Not applicable to Ginna (BWR)
Steel elements: suppression chamber liner	Crack initiation and growth due to SCC	Containment ISI and Containment leak rate test	None	Not applicable to Ginna (BWR)
Steel elements: drywell head and downcomer pipes	Fretting and lockup due to wear	Containment ISI	None	Not applicable to Ginna (BWR)

Class I Structures

Component Group	Aging Effect/Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
All groups except Group 6: accessible interior/exterior concrete and steel components	All types of aging effects	Structures Monitoring	Structures Monitoring Program (B2.1.32)	Consistent with GALL. GALL recommends further evaluation (see Section 3.5.2.2.2.1 below)
Groups 1–3, 5, 7–9: inaccessible concrete components, such as exterior walls below grade and foundation	Aging of inaccessible concrete areas due to aggressive chemical attack and corrosion of embedded steel	Plant specific	Structures Monitoring Program (B2.1.32)	Consistent with GALL. GALL recommends further evaluation (see Section 3.5.2.2.2.2 below)
Group 6: all accessible/inaccessible concrete, steel, and earthen components	All types of aging effects, including loss of material due to abrasion, cavitation, and corrosion	Inspection of Water-Control Structures or FERC/US Army Corps of Engineers dam inspections and maintenance	Structures Monitoring Program (B2.1.32) and Periodic Surveillance and Preventive Maintenance Program (B2.1.23)	Inconsistent with GALL (see Sections 3.5.2.3 and 3.5.2.4 below)
Group 5: liners	Crack initiation and growth from SCC and loss of material due to crevice corrosion	Water Chemistry and monitoring of spent fuel pool water level	Water Chemistry Control Program (B2.1.37)	Consistent with GALL (see Section 3.5.2.1 below)

Component Group	Aging Effect/Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Group 1-3, 5, 6: all masonry block walls	Cracks due to restraint, shrinkage, creep, and aggressive environment	Masonry Wall	Structures Monitoring Program (B2.1.32)	Consistent with GALL (see Section 3.5.2.1 below)
Group 1-3, 5, 7-9: foundation	Cracks, distortion, and increases in component stress level due to settlement	Structures Monitoring	Structures Monitoring Program (B2.1.32)	Consistent with GALL. GALL recommends further evaluation (see Section 3.5.2.2.2.1 below)
Group 1-3, 5-9: foundation	Reduction in foundation strength due to erosion of porous concrete subfoundation	Structures Monitoring	Structures Monitoring Program (B2.1.32)	Consistent with GALL. GALL recommends further evaluation (see Section 3.5.2.2.2.1 below)
Group 1-5: concrete	Reduction of strength and modulus due to elevated temperature	Plant specific	Structures Monitoring Program (B2.1.32)	Consistent with GALL. GALL recommends further evaluation (see Section 3.5.2.2.2.1 below)
Groups 7–8: liners	Crack initiation and growth due to SCC; loss of material due to crevice corrosion	Plant specific	Concrete Tanks (G7); Steel Tanks (G8)	All tanks within the scope of license renewal receive their AMR with the system they serve. Thus, this line item is not applicable to Class 1 structures at Ginna.

Component Supports

Component Group	Aging Effect/Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
All groups: support members, such as anchor bolts, concrete surrounding anchor bolts, welds, grout pad, bolted connections, etc.	Aging of component support	Structures Monitoring	Structures Monitoring Program (B2.1.32) and Periodic Surveillance and Preventive Maintenance Program (B2.1.23)	Consistent with GALL. GALL recommends further evaluation (see section 3.5.2.2.3.1 below)
Groups B1.1, B1.2, and B1.3: support members, such as anchor bolts and welds	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA evaluated in accordance with 10 CFR 54.21(c)	None	A fatigue analysis for structures and component supports is not incorporated into Ginna's CLB (see Section 3.5.2.2.3.2 below)
All groups: support members, such as anchor bolts and welds	Loss of material due to boric acid corrosion	Boric Acid Corrosion	Boric Acid Corrosion Program (B2.1.6)	Consistent with GALL (see Section 3.5.2.1 below)

Groups B1.1, B1.2, and B1.3: support members, such as anchor bolts, welds, spring hangers, guides, stops, and vibration isolators	Loss of material due to environmental corrosion; loss of mechanical function due to corrosion, distortion, dirt, overload, etc.	ISI	ASME Section XI, Subsection IWF Inservice Inspection Program (B2.1.4)	Consistent with GALL (see Section 3.5.2.1 below)
Group B1.1: high-strength, low-alloy bolts	Crack initiation and growth due to SCC	Bolting Integrity	Bolting Integrity Program (B2.1.5)	Consistent with GALL (see Section 3.5.2.1 below)

The staff's review of the structural components for the Ginna LRA is contained in four sections of this SER. Section 3.5.2.1 presents the staff's review of structures and structural components that the applicant indicated are consistent with GALL and do not require further evaluation. Section 3.5.2.2 presents the staff's review of structures and structural components that the applicant indicated are consistent with GALL and for which GALL recommends further evaluation. Section 3.5.2.3 provides the staff's evaluation of the AMPs that are specific to the aging management of structural components. Section 3.5.2.4 contains an evaluation of the adequacy of aging management for components in each structure and includes an evaluation of structures and structural components that the applicant indicates are not in GALL.

3.5.2.1 Aging Management Evaluations in the GALL Report That Are Relied on for License Renewal, Which Do Not Require Further Evaluation

For component groups evaluated in GALL for which the applicant has claimed consistency with GALL, and for which GALL does not recommend further evaluation, the staff sampled components in these groups to determine whether the plant-specific components contained in these GALL component groups are bounded by the GALL evaluation. The staff also sampled component groups to determine whether the applicant had properly identified those component groups in GALL that are not applicable to its plant. The staff identified several areas for which additional information or clarification was needed. The staff's evaluation of the applicant's responses to those RAIs is included in Section 3.5.2.4 of this SER.

On the basis of its review, the staff has verified the applicant's claim of consistency with the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 50.21(a)(3).

3.5.2.2 Aging Management Evaluations in the GALL Report That Are Relied on for License Renewal, for Which GALL Recommends Further Evaluation

For component groups evaluated in GALL for which the applicant has claimed consistency with GALL, and for which GALL recommends further evaluation, the staff reviewed the applicant's evaluation to determine whether it adequately addressed the issues for which GALL recommends further evaluation. In addition, the staff sampled components in these groups to determine whether the plant-specific components contained in these GALL component groups were bounded by the GALL evaluation.

The GALL Report indicates that further evaluation should be performed for the component groups discussed in the following sections.

3.5.2.2.1 Containments

3.5.2.2.1.1 Aging of Inaccessible Concrete Areas. The GALL Report recommends further evaluation to manage the aging effects for containment concrete components located in inaccessible areas if the aging mechanisms of (1) leaching of calcium hydroxide, (2) aggressive chemical attack, or (3) corrosion of embedded steel are significant. Possible aging effects for containment concrete structural components due to these three aging mechanisms are cracking, change in material properties, and loss of material.

The AMP recommended by the GALL Report for managing the above aging effects for containment concrete components in *accessible* portions of the containment structures is the ASME Section XI, Subsection IWL Inservice Inspection Program (XI.S2). The staff's evaluation of the applicant's ASME Section XI, Subsection IWL Inservice Inspection Program is found in Section 3.5.2.3.1 of this SER.

Subsection IWL exempts from examination those portions of the concrete containment that are *inaccessible* (e.g., foundation, below-grade exterior walls, concrete covered by liner). For inaccessible portions of the containment structure, 10 CFR 50.55a(b)(2)(ix) requires that the licensee evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to inaccessible areas.

The applicant addressed the specific criteria defined in the GALL Report regarding the need for further evaluation to manage the potential aging of containment concrete structural components in inaccessible areas in LRA Table 3.6-1. The GALL Report recommends further evaluation for containment concrete in inaccessible areas if the aging mechanisms of (1) leaching of calcium hydroxide, (2) aggressive chemical attack, or (3) corrosion of embedded steel are significant. Regarding these three aging mechanisms, the applicant stated the following in row entry 3.6.1.7 of LRA Table 3.6-1:

> Containment accessible and inaccessible concrete has been evaluated for the following aging mechanisms:
>
> Aging Mechanism: Aggressive Chemical Attack
> Aging Effect: Loss of Material, Changes in Material Properties
> Evaluation: Concrete degradation in air due to aggressive rainwater is insignificant and the below-grade/lake water environment is non-aggressive. Additionally, recent structural inspections revealed no evidence of degradation owing to aggressive chemical attack; therefore, loss of material and change in material properties due to aggressive chemical attack are not probable aging effects at Ginna Station and have not been observed to date. The Structures Monitoring Program requires periodic monitoring of ground/lake water to verify chemistry remains non-aggressive.
>
> Aging Mechanism: Corrosion of Embedded Steel
> Aging Effect: Loss of Material, Cracking, Loss of Bond
> Evaluation: Since the embedded steel is not exposed to an environment which is considered aggressive, loss of material, cracking, and loss of bond due to corrosion of embedded steel are not probable aging effects at Ginna Station and have not been observed to date.

> Aging Mechanism: Leaching of Calcium Hydroxide
> Aging Effect: Change in Material Properties
> Evaluation: The original construction specifications met the intent of ACI 201.2R. Change in material properties due to leaching of calcium hydroxide is not a probable aging effect at Ginna Station and has not been observed to date.

Since the below-grade reinforced concrete at Ginna is not exposed to an aggressive soil/ground water environment, the staff agrees with the applicant's conclusion that the aging mechanisms of aggressive chemical attack and corrosion of embedded steel are not likely to be significant. In addition, because the below-grade reinforced concrete at Ginna is not exposed to flowing water, the staff concludes that leaching of calcium hydroxide from reinforced concrete is not significant. Because these three aging mechanisms are not significant for below-grade reinforced concrete at Ginna, the further evaluation recommended by the GALL Report is not warranted. Further discussion regarding the aging management of inaccessible containment concrete components can be found in Section 3.5.2.4.1 of this SER.

3.5.2.2.1.2 <u>Cracking, Distortion, and Increase in Component Stress Level Due to Settlement; Reduction of Foundation Strength Due to Erosion of Porous Concrete Subfoundations, If Not Covered by Structures Monitoring Program</u>. For the containment foundation, the GALL Report recommends further evaluation of the aging effects of (1) cracking due to settlement and (2) change in material properties as manifested by a reduction of foundation strength due to erosion of the porous concrete subfoundation, if these two effects are not covered by a structures monitoring AMP. In addition, the GALL Report recommends verification of the continued functionality of a dewatering system during the license renewal period, if relied on by the applicant to lower the site ground water level.

The applicant addressed the above criteria defined in the GALL Report regarding the need for further evaluation to manage the potential aging of the containment foundation in LRA Table 3.6-1. In row entries 3.6.1.08, 3.6.1.09, 3.6.1.21, and 3.6.1.22 of LRA Table 3.6-1, the applicant stated that it will use its Structures Monitoring Program to manage the aging effects of (1) cracking due to settlement and (2) change in material properties as manifested by a reduction in strength for the containment foundation. The staff's evaluation of the applicant's Structures Monitoring Program can be found in Section 3.0.3.10 of this SER.

Regarding the aging effect of cracking due to settlement, the applicant stated the following in LRA Table 3.6-1:

> Consistent with NUREG-1801. Cracks, distortion, and increase in component stresses due to settlement of concrete foundations are considered in the Structures Monitoring Program. All structures at Ginna Station are either founded on bedrock, steel foundation piles that are driven to bedrock, or have foundations that consist of caissons extending to bedrock. Structural inspections indicate no visible evidence of settlement since construction of the station. During the Systematic Evaluation Program, the NRC concluded that settlement of foundations and buried equipment is not a safety concern for Ginna Station. Cracking, distortion, and an increase in component stress levels due to settlement are not probable aging effects at Ginna Station and have not been observed to date. That notwithstanding, the Structures Monitoring Program monitors for cracks and distortion and contains inspection criteria to verify these aging effects are not developing.

Regarding the aging effect of change in material properties as manifested by a reduction in strength, the applicant stated the following in LRA Table 3.6-1:

> Consistent with NUREG-1801. Reduction in foundation strength due to erosion of porous concrete subfoundations is not an aging effect requiring management at Ginna. Ginna Station's structure foundations are constructed of normal concrete and not the subject porous type, nor are foundations subject to flowing water. That notwithstanding, the Structures Monitoring Program monitors for settlement and cracking. The identification of indications of settlement by the Structures Monitoring Program, as well as the resistance provided by the materials of construction, provide adequate assurance that reductions in foundation strength for any reason will be identified and managed throughout the extended period of operation.

Because the applicant is managing the aging effects of cracking and change in material properties for the containment foundation as recommended by the GALL Report, the staff finds that the applicant has adequately addressed this further evaluation criteria.

3.5.2.2.1.3 <u>Reduction of Strength and Modulus of Concrete Structures Due to Elevated Temperature</u>. For the containment structure, the GALL Report recommends further evaluation to manage the aging effect of change in material properties as manifested by a reduction in strength and modulus if any portion of the containment concrete exceeds the temperature limit of 150 °F. The GALL Report notes that the implementation of Subsection IWL examinations and 10 CFR 50.55a would not be able to detect the reduction of concrete strength and modulus due to elevated temperature. The GALL Report also notes that no mandated aging management exists for managing this aging effect.

The GALL Report recommends that a plant-specific evaluation be performed if any portion of the concrete containment components exceeds specified temperature limits, viz., general temperature 66 °C (150 °F) and local area temperature 93 °C (200 °F). The staff verified that the applicant's discussion in the renewal application indicates that the affected PWR containment components are not exposed to temperatures that exceed the above temperature limits.

The applicant addressed the above criterion defined in the GALL Report regarding the need for further evaluation in LRA Table 3.6-1. In row entries 3.6.1.10 and 3.6.1.23 of LRA Table 3.6-1, the applicant stated the following regarding temperatures within the containment structure:

> Consistent with NUREG-1801. For plant areas of concern, temperatures are normally maintained below the specified limits; therefore, loss of material, cracking, and change in material properties due to elevated temperature at Ginna Station have not been observed to date. (Note: The SSCs relied upon to maintain the concrete surrounding containment penetrations and the reactor vessel support pad within specified temperature limits are within the scope of the License Renewal Rule, i.e., penetration cooling and component cooling water.) That notwithstanding, the ASME Section XI, Subsections IWE & IWL Inservice Inspection Program monitors for loss of material, cracks, and changes in material properties and contains inspection criteria to verify these aging effects are not developing.

In RAI 3.6-5, the staff requested further information regarding the aging mechanism of elevated temperature for containment concrete components. Specifically, the staff requested that the applicant provide (1) sustained temperatures in the annulus between the primary shield wall and the reactor and in the concrete components around the steam generators, (2) the observed condition of the concrete components during the last inspection, and (3) the schedule for inspection of these components. In response to RAI 3.6-5, the applicant stated the following:

> The normal operating temperature of the air flowing through the annulus is approximately 80 degrees F. This air flows around the vessel, instrument ports, and vessel nozzles where air temperatures reach a normal maximum of approximately 130 degrees F. The air temperatures associated with the annulus, reactor vessel nozzles and the head shroud fan suctions and the water temperatures for the reactor vessel support pad cooling system are continuously recorded and displayed in the control room.
>
> No permanent telemetry is installed that monitors the temperatures associated with the concrete around the steam generators; however, temporary RTDs were placed in the containment over a number of operating cycles to verify temperatures used in equipment environmental qualification calculations. Some of these RTDs were in the inside the shield walls and near the steam generator level indications. These RTDs indicate local area temperatures are normally below 100 degrees F.
>
> No loss of material has been observed in the primary shield wall, the annulus region or in the vicinity of the steam generators. Some of these areas are routinely inspected where they interface with ASME component supports. The next general inspection is scheduled for the fall 2003 outage as part of the Structural Monitoring Program.

Based on the discussion in the LRA and in response to RAI 3.6-5, the staff noted that the high temperature areas of the containment concrete will be monitored by Subsection IWL of Section XI of the ASME Code, and the concrete components subjected to sustained high temperatures inside the containment will be monitored by the applicant's Structures Monitoring Program. The staff finds acceptable the use of these two programs for managing the aging of concrete components of the containment and those inside the containment. The Subsection IWL Program and the Structures Monitoring Program are evaluated in Sections 3.5.2.3.1 and 3.0.3.10, respectively, of this SER. As such, RAI 3.6-5 is considered closed.

On the basis of its review, the staff finds that the applicant appropriately evaluated AMR results involving management of the reduction of strength and modulus of concrete structures due to elevated temperatures for containment concrete, as recommended in the GALL Report. Because temperatures within the containment structure have not exceeded the 150 °F limit, the staff concludes that further evaluation, as recommended by the GALL Report, is not required.

3.5.2.2.1.4 Loss of Material due to Corrosion in Inaccessible Areas of Steel Containment Shell or Liner Plate. The GALL Report recommends further evaluation to manage the aging effect of loss of material due to corrosion for the embedded containment liner, if corrosion of the embedded liner is significant. The AMP recommended by the GALL Report for managing loss of material for *accessible* steel elements within the containment structure is the ASME Section XI, Subsection IWE Program (XI.S1). The staff's evaluation of the applicant's ASME Section XI, Subsection IWE Inservice Inspection Program is found in Section 3.5.2.3.1 of this SER.

Subsection IWE exempts from examination portions of the containment that are *inaccessible*, such as embedded or inaccessible portions of steel liners and steel containment shells, piping, and valves penetrating or attaching to the containment. To cover inaccessible areas, 10 CFR 50.55a(b)(2)(ix) requires that the licensee evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to inaccessible areas.

The applicant addressed the above criterion defined in the GALL Report regarding the need for further evaluation to manage the aging of the embedded containment liner in LRA Table 3.6-1. In row entry 3.6.1.12 of LRA Table 3.6-1, the applicant stated the following regarding the potential for significant corrosion of the embedded steel containment liner:

> Consistent with NUREG-1801. The ASME Section XI, Subsections IWE & IWL Inservice Inspection Program includes inspections and leak rate tests which would indicate the presence of significant degradation due to loss of material from all applicable corrosion mechanisms. Additionally, plant operating experience has shown that borated water spills in containment have the potential to impact the containment liner. Accordingly, the Boric Acid Corrosion Program is also credited with assessing and managing loss of material in the containment liner.

Because the above statement does not address the criterion regarding the need for further evaluation if corrosion of the embedded liner is significant, the staff requested the applicant in RAI 3.6-16 to specifically address the GALL criterion for further evaluation. In response to RAI 3.6-16, the applicant stated the following:

> Review of plant-specific operating experience and recent maintenance and corrective action documents identified only one nonconforming condition at the moisture barrier (caulking) which protects the inaccessible portion of the Containment steel liner from corrosion. This condition was discovered during inservice inspections performed to meet the requirements of ASME Section XI, Subsection IWE in 2000. As discussed in the response to RAI B2.1.3-3, insulation was removed and the liner was exposed for visual inspection in two areas. Evidence of minor surface corrosion was present in the area with the nonconforming caulking detail. Ultrasonic thickness readings were taken in both areas, including locations above and along the interface between the liner and the Containment concrete floor. All measured values exceeded the minimum required thickness with considerable margin. The liner was cleaned, re-coated and the moisture barrier restored in accordance with original design specification requirements in both areas.
>
> As a result of this discovery, the configuration of the moisture barrier was inspected around the entire circumference of the Containment and verified to be intact with no visible gaps or discontinuities. Additional inspections of the liner were performed during the 2002 refueling outage. As discussed in the response to RAI B2.1.3-3, approximately 70 linear feet of the liner were exposed and ultrasonic thickness measurements taken at four different excavated areas below the floor level. These measurements verified that no loss of liner thickness had occurred at these locations. The exposed portion of the liner was again cleaned, re-coated, and the moisture barrier restored in accordance with original design specification requirements.
>
> Additional inspections of the moisture barrier and liner are planned during the second and third periods of the Fourth ISI interval, which commenced on January 1, 2000. The condition of the inaccessible portions of the Containment liner may be assessed by evaluation of the condition of the liner at the interface with the concrete floor. Therefore, inspections performed under the ASME Section XI, Subsections IWE/IWL ISI Program will provide reasonable assurance that aging effects for the inaccessible portions of the liner plate can be managed so that the liner plate will continue to perform its intended function consistent with the current licensing basis during the period of extended operation.

Since previous inspections of the inaccessible portions of the liner (behind the moisture barrier) revealed only minor degradation, and since additional inspections of both the moisture barrier and liner will take place under the applicant's ASME Section XI, Subsections IWE and IWL Inservice Inspection Program, the staff finds that the applicant has provided a reasonable basis for concluding that the aging of the containment liner behind the insulation and the moisture barrier will be adequately managed consistent with its CLB during the extended period of operation.

In addition, the ASME Section XI, IWE and IWL Inservice Inspection Program manages the aging of the accessible portions of the liner with the stipulation that the applicant evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to inaccessible areas. As such, the staff considers RAI 3.6-16 closed. The staff's evaluation of RAI B.2.1.3-3, which further covers the aging management of the containment liner by the ASME Section XI, Subsections IWE and IWL Inservice Inspection Program, is discussed in Section 3.5.2.3.1 of this SER.

On the basis of its review, the staff finds that the applicant appropriately evaluated AMR results involving management of loss of material due to corrosion in inaccessible areas of the steel containment shell or liner plate for structures and structural components, as recommended in the GALL Report. Because the corrosion of the embedded steel containment liner is not significant, the further evaluation recommended by the GALL Report is not warranted.

3.5.2.2.1.5 <u>Loss of Prestress Due to Relaxation, Shrinkage, Creep, and Elevated Temperature</u>. The GALL Report identifies loss of prestress due to relaxation, shrinkage, creep, and elevated temperature for prestressed containment tendons and anchorage components as a TLAA to be performed for the period of license renewal. The applicant addressed this aging effect for this component grouping in row entry 3.6.1.11 of LRA Table 3.6-1. However, in its review of Section 2.4, "Scoping and Screening Results: Structures," the staff found that row entry 3.6.1.11 was not applied to the containment component group for tendons in LRA Table 2.4.1-1. In RAI 3.6-11, the staff requested that the applicant explain this omission. In response to RAI 3.6-11, the applicant stated the omission was due to a "typographical error" and that row entry 3.6.1.11 of LRA Table 3.6-1 does apply to the containment tendons. The staff finds the applicant's response to be adequate. The applicant covered the TLAA for containment tendons in Section 4.5 of the application. The staff evaluation of this TLAA is addressed in Section 4.5 of this SER.

3.5.2.2.1.6 <u>Cumulative Fatigue Damage</u>. The GALL Report identifies cumulative fatigue damage as a TLAA for penetration sleeves, penetration bellows, and dissimilar metal welds to be performed for the period of license renewal. The applicant covered this TLAA in Section 4.7.4 of the application. The staff evaluation of this TLAA is addressed in Section 4.7.4 of this SER.

3.5.2.2.1.7 <u>Cracking Due to Cyclic Loading and SCC</u>. The GALL Report recommends further evaluation of the AMPs to manage cracking of containment penetrations (including penetration sleeves, penetration bellows, and dissimilar metal welds) due to cyclic loading or SCC for all types of PWR containments. Containment ISI and leak rate testing may not be sufficient to detect cracks. The staff evaluated the applicant's proposed programs to verify that adequate inspection methods will be implemented to ensure that cracking of containment penetrations is detected.

The applicant addressed the further evaluation recommendations in the GALL Report with regard to cracking of containment penetrations in LRA Table 3.6-1. In row entry 3.6.1.02 of LRA Table 3.6-1, the applicant stated the following with regard to the aging effect of cracking due to cyclic loading or SCC:

> The Containment Program implements and formally adopts the requirements of the ASME Section XI, Subsections IWE & IWL Inservice Inspection Program as part of the Ginna Station Inservice Inspection Program. Included in the scope of the IWE program are the exposed portions of the containment liner,

> the liner for the fuel transfer penetration, all other penetrations, associated bolting, moisture barriers, and all airlocks, seals, gaskets and penetration bellows previously included in the scope of Appendix J. The ASME Section XI, Subsections IWE & IWL Inservice Inspection Program includes inspections and leak rate tests which would indicate the presence of significant degradation from cracking due to cyclic loading or crack initiation and growth due to SCC. That notwithstanding, SCC is not an applicable aging mechanism for penetration sleeves, bellows and dissimilar metal welds. The carbon steel components within penetrations are not susceptible to SCC. The stainless steel components require both a high temperature (>140 °F) and exposure to an aggressive chemical environment (e.g., exposure to chlorides). The bellows at Ginna Station are not exposed to aggressive chemical environments. A review of plant specific operating experience did not identify any occurrences of bellows failures due to SCC. Furthermore a review of industry operating experience indicated that SCC of bellows was typically caused by poor design controls leading to the inadvertent introduction of contaminants.

In RAI 3.6-3, the staff requested additional information regarding (1) the type of bellows (e.g., one ply or two ply), (2) the accessibility of the bellows for ASME Section XI, Subsection IWE inspections, (3) the ability to detect leakage from the bellows by Type B (Appendix J) testing, and (4) occurrences of excessive leakage through the bellows. In response to RAI 3.6-3, the applicant stated the following:

> There are no penetration bellows at Ginna Station which perform a Containment isolation function. The bellows are single ply, ASTM A240, Type 304 stainless steel. The only function of the bellows is to accommodate lateral and axial pipe displacements.

Based on the applicant’s assertion regarding the absence of pressure boundary bellows, the staff considers RAI 3.6-3 closed.

On the basis of its review, the staff finds that the applicant appropriately evaluated AMR results involving management of cracking of containment penetrations (including penetration sleeves, penetration bellows, and dissimilar metal welds) due to cyclic loading and SCC, as recommended in the GALL Report. A complete review of the applicant’s Containment Inservice Inspection Program can be found in Section 3.5.2.3.3 of this SER.

3.5.2.2.1.8 Conclusions. On the basis of its review, the staff finds that the applicant appropriately evaluated AMR results involving management of containment structural components, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with the GALL Report, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.2.2 Class I Structures

3.5.2.2.2.1 Aging of Structures Not Covered by the Structures Monitoring Program. The GALL Report recommends further evaluation for certain structure/aging effect combinations if they are not covered by the applicant’s structures monitoring program. This includes (1) scaling, cracking, and spalling due to repeated freeze-thaw for Groups 1–3, 5, and 7–9 structures, (2) scaling, cracking, spalling, and an increase in porosity and permeability due to leaching of calcium hydroxide and aggressive chemical attack for Groups 1–3, 5, and 7–9 structures, (3) expansion and cracking due to reaction with aggregates for Groups 1–3, 5, and 7–9 structures, (4) cracking, spalling, loss of bond, and loss of material due to corrosion of embedded steel for Groups 1–5 and

7–9 structures, (5) cracks, distortion, and increase in component stress level due to settlement for Groups 1–3, 5, and 7–9 structures, (6) reduction of foundation strength due to erosion of porous concrete subfoundation for Groups 1–3 and 5–9 structures, (7) loss of material due to corrosion of structural steel components for Groups 1–5 and 7–8 structures, (8) loss of strength and modulus of concrete structures due to elevated temperatures for Groups 1–5 structures, and (9) crack initiation and growth due to SCC and loss of material due to crevice corrosion of stainless steel liner for Groups 7–8 structures. Further evaluation is necessary only for structure/aging effect combinations that are not covered by the applicant's structures monitoring program.

The applicant addressed the above criterion defined in the GALL Report regarding the need for further evaluation to manage the potential aging of concrete and steel structural components in LRA Table 3.6-1. In row entry 3.6.1.16 of LRA Table 3.6-1, the applicant stated that it will use its Structures Monitoring Program to manage the aging effects identified in the preceding paragraph. Specifically, the applicant stated the following:

> The Structures Monitoring Program identifies the evidence that an aging mechanism is present and active and also provides confirmation and verification of the absence of all types of aging effects. Indication of aging effects may be absent if the materials of construction, design specifications, and operational environment preclude an aging mechanism but, due to the long lead time necessary for some effects to manifest themselves, it is prudent to periodically assess the condition of SSCs regardless of the likelihood that a particular aging mechanism is applicable. The degradation of inaccessible concrete can create symptoms of aging effects that are detectable in accessible areas. Conversely, if aging effects are present in accessible areas it is sensible to extrapolate those effects into inaccessible areas and perform additional evaluations.

Because the applicant is managing the aging effects for the concrete and steel structural items covered by row entry 3.6.1.16 of LRA Table 3.6-1, as recommended by the GALL Report, the staff finds that the applicant has adequately addressed this further evaluation criterion. The staff's evaluation of the applicant's Structures Monitoring Program can be found in Section 3.0.3.10 of this SER.

3.5.2.2.2.2 Aging Management of Inaccessible Areas. The GALL Report recommends further evaluation for aging of inaccessible concrete areas, such as below-grade foundation and exterior walls exposed to ground water, due to aggressive chemical attack, if an aggressive below-grade environment exists. An aggressive below-grade environment could result in either cracking or loss of material for concrete components subjected to such an environment. The GALL Report recommends that a plant-specific AMP be developed by the applicant if an aggressive below-grade environment exists.

The applicant addressed the above criterion defined in the GALL Report regarding the potential aging of below-grade concrete exposed to an aggressive environment in LRA Table 3.6-1. In row entry 3.6.1.17 of LRA Table 3.6-1, the applicant stated the following:

> Inaccessible wall and concrete foundations are considered in the Structures Monitoring Program. Results of inspections for accessible concrete are evaluated and, if aging effects are noted, the Structures Monitoring Program evaluates the symptom and possible causes with respect to inaccessible areas. The Structures Monitoring Program requires periodic monitoring of ground water to verify chemistry remains non-aggressive. Concrete degradation in air due to aggressive rainwater is insignificant and the below-grade/lake water environment is non-aggressive. Additionally, recent structural inspections revealed no evidence of degradation owing to aggressive chemical attack;

> therefore, degradation due to chemical attack is not a probable aging effect at Ginna Station. The concrete at Ginna Station was designed in accordance with ACI 301-66 or ACI 318-63. ACI 301-66 refers to ACI 318 for concrete reinforcement. Designing concrete to ACI 318 also provides for sufficient concrete cover over embedded steel to provide ample corrosion protection. Chemical analyses performed on the rock and ground water indicate these environments are non-aggressive. Since the embedded steel is not exposed to an environment which is considered aggressive, corrosion of embedded steel is not a probable aging effect at Ginna Station and has not been observed to date.

In RAI 3.6-4, the staff requested that the applicant provide the results of the Groundwater Monitoring Program, in terms of chlorides, sulfates, and pH of the ground water, in order for the staff to verify the applicant's claim of a nonaggressive, below-grade environment. In response to RAI 3.6-4, the applicant stated, "the most recent samples ranged between 6 and 8 ppm chloride, 20 to 40 ppm sulfate, and a pH of 7.0." Since these ground water chemistry values do not constitute an aggressive environment, as specified in the GALL Report (pH less than 5.5, sulfates greater than 1500 ppm, chlorides greater than 500 ppm), the staff finds that the applicant's claim of a nonaggressive, below-grade environment to be accurate. As such, further evaluation, as recommended by the GALL Report, is unnecessary. In addition, the applicant's Structures Monitoring Program requires periodic monitoring of ground/lake water to verify that the chemistry remains nonaggressive. Therefore, RAI 3.6-4 is considered closed.

On the basis of its review, the staff finds that the applicant has adequately evaluated the potential aging of below-grade concrete components exposed to ground water due to an aggressive environment. Since the below-grade environment is not aggressive, the further evaluation recommended by the GALL Report is not warranted.

3.5.2.2.2.3 <u>Conclusions</u>. On the basis of its review, the staff finds that the applicant appropriately evaluated AMR results involving management of Class I structures, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with the GALL Report, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.2.3 Component Supports

3.5.2.2.3.1 <u>Aging of Supports Not Covered by the Structures Monitoring Program</u>. The GALL Report recommends further evaluation of certain component support/aging effect combinations if they are not covered by the Structures Monitoring Program. These include (1) reduction in concrete anchor capacity due to degradation of the surrounding concrete for Groups B1–B5 supports, (2) loss of material due to environmental corrosion for Groups B2–B5 supports, and (3) reduction/loss of isolation function due to degradation of vibration isolation elements for Group B4 supports.

Further evaluation is necessary only for the structure/aging effect combinations listed above that are not covered by the applicant's Structures Monitoring Program.

The applicant addressed the above criterion defined in the GALL Report regarding the need for further evaluation to manage the potential aging of component supports in LRA Table 3.6-1. In row entry 3.6.1.25 of LRA Table 3.6-1, the applicant stated that it will use its Structures Monitoring

Program to manage the aging effects identified in the preceding paragraph. Specifically, the applicant stated the following in row entry 3.6.1.25:

> The aging effects associated with component supports are considered in the Structures Monitoring Program. Additionally, component supports submerged in raw water are considered in the Periodic Surveillance and Preventive Maintenance Program. Component supports include those structural elements that are connected to civil structures and which extend to a system or system components for the purpose of providing support or restraint. Inclusive in this boundary definition are any vibration dampeners or other passive connective appurtenances intrinsic to the functioning of the support. The group also includes spray or drip shields attached to equipment as well as electrical system rack, panels and enclosures. Component supports are located throughout the plant. Included in the evaluation of the component supports are supports for both safety-related components and nonsafety-related components whose failure could affect a safety function (typically referred to as seismic II/I).

Because the applicant is managing the aging effects for the component supports covered by row entry 3.5.1.25 of LRA Table 3.5-1, as recommended by the GALL Report, the staff finds that the applicant has adequately addressed this further evaluation criterion. The staff's evaluation of the applicant's Structures Monitoring Program can be found in Section 3.0.3.10 of this SER.

3.5.2.2.3.2 <u>Cumulative Fatigue Damage Due to Cyclic Loading</u>. The GALL Report identifies cumulative fatigue damage as a TLAA for support members, anchor bolts, and welds for Groups B1.1, B1.2, and B1.3 component supports if a CLB fatigue analysis exists. Since a CLB fatigue analysis does not exist at Ginna Station, cumulative fatigue damage for component supports is not addressed by the applicant as a TLAA. Although a CLB fatigue analysis does not exist at Ginna, in RAI 3.6-14, the staff requested that the applicant explain how the aging effect of cumulative fatigue for supports for ASME piping and components will be managed during the period of extended operation. In response to RAI 3.6-14, the applicant stated the following:

> Consistent with the Ginna CLB (Reference 1), supports for ASME piping and components were qualified and designed to the requirements of ASME III, Subsection NF (Reference 2) and AISC Manual (Reference 3). Both codes had accounted for fatigue cyclic loads by limiting the allowable stress ranges corresponding to cycles as high as greater than 2E6 cycles which bounds the number of cycles anticipated during 60 years of operation.
>
> The Westinghouse Owners' Group Generic Technical Report (Reference 4), which has been approved by the NRC subject to limitations which were addressed in the LRA, concluded that fatigue cumulative usage factors for supports are much less than 1.0, even when effects of the extended period of operation are included. The conclusion of the evaluation is that fatigue is not an aging effect requiring management, and consequently no aging management program is needed.
>
> Nevertheless, RG&E inspects for aging degradation of supports, including the effects of fatigue for supports of ASME piping and components, utilizing an inspection program which is documented in References 5 and 6. This program conforms to the requirements of Subsection IWF of ASME Section XI (Reference 7).
>
> The RG&E in-service inspection program provides a Category F-A and VT-3 examination of Class 1, 2, and 3 piping supports and supports for other safety-related components. It monitors and inspects for evidence of fatigue such as deformation or structural degradation of support parts. Non-conformances are administratively controlled in accordance with Reference 8. Repair or replacement actions to mitigate the consequences of fatigue (crack initiation and growth) are specified in Section 12 of the In-service Inspection Program documented in Reference 5.
>
> References:
>
> 1. Ginna UFSAR, Section 3.9.3.3, "Pipe Supports."

2. ASME Boiler and Pressure Vessel Code, 1974 Edition, Section III, Subsection NF.
3. Manual of Steel Construction, AISC, 7th Edition.
4. Westinghouse Report, WCAP-14422 Rev. 2-A, "License Renewal Evaluation: Aging Management for Reactor Coolant System Supports," December 2000.
5. RG&E In-service Inspection Program, November 2, 2001.
6. RG&E Nuclear Directive, ND-IIT, "In-service Inspection and Testing."
7. ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWF, 1995 Edition with 1996 Addenda.
8. RG&E Procedure IP-CAP-1,"Abnormal Condition Tracking Initiation or Notification (ACTION) Report."

Because the supports for ASME piping and components are qualified and designed to codes that account for fatigue cyclic loads as high as $2x10^6$ cycles, which bounds the number of cycles anticipated during 60 years of operation, the staff finds the AMR of this component to be adequate. In addition, the Westinghouse Owners' Group Generic Technical Report, WCAP-14422 (Reference 4 above), which has been approved by the NRC subject to limitations which were addressed in the LRA, concludes that fatigue cumulative usage factors for supports are much less than 1.0, even when the effects of the extended period of operation are included. WCAP-14422 concluded that fatigue is not an aging effect requiring management, and consequently no AMP is needed.
As such, the staff considers RAI 3.6-14 closed.

3.5.2.2.3.3 Conclusions. On the basis of its review, the staff finds that the applicant appropriately evaluated AMR results involving management of component supports, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with the GALL Report, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.3 Aging Management Programs for Containment, Structures, and Component Supports

In SER Section 3.5.2.1, the staff evaluated the applicant's conformance with the aging management recommended by GALL for containment, other Class I structures, and component support component groupings. In SER Section 3.5.2.2, the staff reviewed the applicant's evaluation of the issues for which GALL recommends further evaluation. In this SER section, the staff presents its evaluation of the programs used by the applicant to manage the aging of the component groups within the containment, other Class I structures, and component supports.

The applicant credits nine AMPs to manage the aging effects associated with the containment, other Class I structures, and component supports. Five of the AMPs are credited to manage aging for components in other system groups (common AMPs), while four AMPs are credited with managing aging only for structures and structural components. The staff's evaluation of the common AMPs credited with managing aging in structures and structural components is provided in Section 3.0.3 of this SER. The common AMPs are listed below:

- Bolting Integrity Program (3.0.3.3)
- Boric Acid Corrosion Prevention Program (3.0.3.4)
- Periodic Surveillance and Preventive Maintenance Program (3.0.3.8)
- System Monitoring Program (3.0.3.11)

- Water Chemistry Program (3.0.3.1)

The staff's evaluation of the three structure-specific AMPs is provided in the following subsections.

3.5.2.3.1 ASME Section XI, Subsections IWE and IWL Inservice Inspection Program

3.5.2.3.1.1 Summary of Technical Information in the Application. The applicant describes its ASME Section XI, Subsections IWE and IWL Inservice Inspection Program in Section B2.1.3 of the LRA. The LRA states that this program is consistent with GALL Programs XI.S1, "ASME Section XI, Subsection IWE"; XI.S2, "ASME Section XI, Subsection IWL"; and XI.S4, "10 CFR 50, Appendix J." The applicant credits this program with aging management of (1) steel liners of concrete containments and their integral attachments; containment hatches and airlocks; seals, gaskets, and moisture barriers; and pressure retaining bolting, and (2) reinforced concrete containments and unbonded post tensioning systems. Ginna Station has maintained an ISI program in accordance with 10 CFR 50.55a and technical specification requirements.
The containment program which outlines the first IWE and IWL inservice inspection interval requirements for Ginna Station was implemented on September 9, 1998, and was formally included in the ASME Section XI Inservice Inspection Program.

The applicant provided a summary of the operating experience and corrective measures as follows:

- loss of prestress in most containment tendons; retensioning of 137 tendons
- containment moisture barrier found to be out of conformance with drawing due to loose insulation; nonconformance corrected by recaulking
- minor corrosion of steel containment liner with wall thickness verified by UT; restoration by protective paint coating
- low grease levels in certain tendon grease cans at top of containment; cans refilled
- corroded and leaking tendon fill-port piping; all fill ports repaired

In its LRA, the applicant stated that the ASME Section XI, Subsections IWE and IWL Inservice Inspection Program provides an effective means for timely detection and correction of any degradation of the containment pressure boundary, concrete, and post-tensioning system and concluded that continued implementation of this program will be managed such that the intended functions of the containment will be maintained throughout the license renewal period.

3.5.2.3.1.2 Staff Evaluation. In addition to the review of Section B2.1.3 of the LRA, the staff reviewed the relevant information in Sections 2.4 and 3.6 of the LRA. Under this program, the applicant combined the aging management of the metallic pressure boundary, concrete, and post-tensioning components of the Ginna Station containment during the extended period of operation. For the aging management of these components, the LRA states this program is consistent with Section XI.S1, "ASME Section XI, Subsection IWE," and Section XI.S2, "ASME Section XI, Subsection IWL," of the GALL Report. In addition, for the aging management of certain pressure boundary components, and performance monitoring of the containment and its components, the

LRA states this program is consistent with Section XI.S4, “10 CFR Part 50, Appendix J,” of the GALL Report. The staff confirmed the applicant’s claim of consistency during the AMP audit. In addition, the staff determined whether the applicant properly applied the GALL program to its facility.

To make a reasonable conclusion regarding the implementation of the program, the staff requested information from the applicant in RAIs B2.1.3-1, B2.1.3-2, B2.1.3-3, B2.1.3-4, and B2.1.3-5.

In RAI B2.1.3-1, the staff requested the applicant to provide a summary of the corrective actions taken, including the root cause determination, and the results of subsequent inspections related to the prestressing tendon surveillance.

In its response, dated May 13, 2003, the applicant provided the following information:

> During lift-off surveillance testing in 1977 it was discovered that the average compressive force of the tendons had decreased to a value marginally above the design requirement of 636 kips. A 10-year retest was performed in 1979 and the marginal force values confirmed. In 1980, a total of 137 tendons were retensioned. In 1981, lift-off surveillance tests were performed, and witnessed by NRC inspectors (see Inspection Report 81-14). Subsequent surveillance testing has demonstrated that all tendons have met operability criteria. Investigation of the cause of the loss of prestress was undertaken at the Fritz Engineering Laboratory of Lehigh University. An extensive testing program was conducted with two primary objectives. The first objective was to determine the root cause of the loss of prestress, and the second was to determine the effect of retensioning at various times after initial stressing on subsequent loss of prestress. The results of the testing program can generally be summarized as follows (Refs. 1 and 2):
>
> (1) The principal cause of the loss of prestress in the wall tendons was stress relaxation;
>
> (2) An increase in temperature from ambient conditions to operating conditions significantly increases the amount of stress relaxation over time. For example, at a temperature of 104 °F after 40 years the stress relaxation in the tendon would be expected to be as high as 21% as opposed to 12% as originally predicted;
>
> (3) Retensioned tendons exhibit considerably less stress relaxation than initially tensioned tendons.

In its response, dated May 13, 2003, the applicant also provided information regarding the root cause of the tendon prestress loss:

> The results of the Lehigh University testing program were reviewed by Franklin Research Center (FRC) and Geotechnical Engineers, Inc. The reviews included assessment of other potential contributions to loss of tendon prestress, such as rock anchor slippage, bedrock creep, creep in concrete containment walls, elastic shortening of the containment concrete, tendon stress relaxation, and tendon wire corrosion. It was concluded that stress relaxation was the most reasonable and probable cause of the loss of prestress (Refs. 3 and 4). The review concluded that contributions from rock anchor slippage and creep of concrete containment walls were significantly less than the contribution from stress relaxation. The NRC agreed with this analysis and concluded that the tendon lift-off surveillance program should be continued.
>
> Tendon lift-off surveillance tests were performed in 1981, 1983, and 1985, and thereafter, every five years (1990, 1995 and 2000). Regulatory Guide 1.35 requires that at least 4% of the population of each tendon group be randomly sampled during each surveillance. The tendon group for Ginna Station consists of 160 vertical tendons, and 4% amounts to a sample size of 7 per surveillance. The actual test sample size during each lift-off surveillance testing activity since retensioning has ranged from 14 to 21, well in excess of the minimum required by the regulatory guide. The measured

> lift-off forces in all surveillance tests performed to date have exceeded the minimum required prestress force.

The applicant cited the following references in support of its response to RAI B2.1.3-1:

- Containment Building Tendon Investigation, GAI Report 2347, Doc. No. GC 20224, EWR 1900, Record ID GC20224, 1981.
- Evaluation of Lehigh Retension Tendon Stress Relaxation Data to Predict Tendon Surveillance Forces, Doc. No. GC20250, EWR 1900, Record ID GC20250, 1983.
- Tendon Evaluation, Rochester Gas and Electric Corp., R.E. Ginna Nuclear Power Station, Technical Evaluation Report C5506-551, Franklin Research Center, March 29, 1985.
- Review of Rock Anchor Evaluation, R.E. Ginna Nuclear Power Plant, Geotechnical Engineers, Inc., January 10, 1985.
- U.S. NRC Letter dated August 19, 1985 from John A. Zwolinski to R.W. Kober.

In its evaluation of the applicant's response to RAI B2.1.3-1, the staff found the root cause and corrective actions implemented for the loss of tendon prestress to be informative. Based on the applicant's plans to closely monitor the containment tendon system, as discussed in Section 4.5 of this SER, the staff finds the applicant's actions acceptable for the extended period of operation.

In RAI B2.1.3-2, the staff requested information regarding the inspection of the unique support system of Ginna containment, and pointed out that its inspection requirements are not specifically addressed in Subsections IWE and IWL of Section XI of the ASME Code.

In its response, dated May 13, 2003, the applicant provided the following information:

> As of September 2000, the containment system at Ginna Station is inspected and monitored according to the provisions of the ASME Code, Section XI, Subsections IWE and IWL as implemented by the Ginna Station containment program. The functionality of the structure will be monitored for structural adequacy of its unique support system by successful completion of testing performed under the containment tendon surveillance program, as defined in plant procedure PT 27.2, "Tendon Surveillance Program." The material condition and functionality of the containment structure is also evaluated under the provisions defined in Engineering Procedure EP-2-P-0169, "Structural Assessment and Monitoring Program," which provides guidance for evaluating galvanic potential measurements for the rock anchor tendons.

In its evaluation of the applicant's response to RAI B2.1.3-2, the staff recognized that the applicant is aggressive in performing tendon inspections, and that the tendon inspections provide a certain degree of confidence regarding the integrity of the rock anchor system coupled to the tendons. However, it is for the other inaccessible features of the containment that the staff needs additional assurance for the extended period of operation. Inspections performed in accordance with the requirements of Subsection IWL of Section XI of the ASME Code will not be able to detect problems with the (1) tendon bellows, (2) elastomer pads, and (3) radial tension bars. Moreover, the areas of the containment where these components are located are below the ground water level, and the staff had identified water-related problems around the elastomer pads in the early 1990s. The applicant needs to develop an AMP (or periodic functional tests) that would verify the containment functionality at the location of the containment support. In a subsequent discussion with the applicant, the staff suggested that the applicant perform two or three structural integrity tests (SITs) during the extended period of operation. An SIT could be performed at the peak calculated pressure that would demonstrate conformance with the expected behavior of the lower part of the containment. SIT measurements would consist of radial and vertical deformations, similar to the measurements taken during initial and subsequent SITs, and visual observations during and after the tests. The comparison will allow the applicant to detect significant deviation from the containment expected behavior.

In a letter dated July 30, 2003, the applicant committed to perform two SITs during the extended period of operation, one in 2009 and one in 2029 (reference item 27 in Appendix A to this SER). The staff finds the commitment acceptable, as it would periodically verify the behavior of the containment in the lower portion of the containment. Evaluation of the test results would indicate if there is a gross change in the containment behavior which would indicate significant degradation of the inaccessible components.

In RAI B2.1.3-3, the staff requested the following information regarding moisture barrier degradation and corrosion of the liner:

(a) the acceptance criteria used for repairing the liner plate

(b) the successive (IWE-2420), additional (IWE-2430), and augmented (IWE-2500(c)) liner inspections performed (and to be performed)

(c) sampling plans (if any) for removing the insulation for the purpose of inspection

In its response, dated May 13, 2003, the applicant provided the following information regarding items (a) and (b) of RAI B2.1.3-3:

> During scheduled ASME Section XI, Subsection IWE inspections of the containment circumference at the intersection of the basement concrete floor with the containment steel liner, one area was discovered where the sealing (caulking) detail of the concrete floor to liner plate did not conform to drawings. The caulking seals the gap between the foam insulation on the containment walls and the concrete floor. As a result of this discovery, the inspection scope was increased to include a visual inspection of the caulking detail around the entire circumference of the containment concrete/liner interface. The caulking was found to be continuous with no visible gaps or discontinuities.
>
> As a result of the discovery of the non-conforming caulking detail, insulation in two areas (one on the north side and one on the west side of the containment) was removed and the containment liner was visually inspected. Evidence of minor surface corrosion was visible in the area of non-conforming caulking detail (north side). Ultrasonic thickness readings were taken in both areas. The thickness readings ranged from 0.346" to 0.404" on the north side, and 0.388" to 0.404" on the west side. The minimum required thickness was determined by engineering analysis and documented in EWR 5190 to be 0.281". Therefore the minimum liner thickness requirements were met.
>
> The containment liner surface had been coated with a layer of zinc-rich paint during construction. The area of the liner which exhibited minor surface corrosion was cleaned and restored with a new coating of zinc-rich paint. The foam insulation was restored in both areas and new caulking installed in conformance with engineering specifications.

In its response, dated May 13, 2003, the applicant stated the following information regarding item (c) of RAI B2.1.3-3, "Additional inspections of the caulking and containment liner are scheduled during the second and third periods of the Fourth Ten-Year Inservice Inspection Interval which commenced January 1, 2000."

The staff found that the applicant's response to RAI B2.1.3-3 items (a) and (b) was not clear as to whether the liner plate was restored to its nominal thickness before recoating. The applicant was requested to clarify this issue. The applicant was also requested to include a sampling plan for removing the insulation for examining the liner surfaces in a clarification to RAI B2.1.3-3 item (c).

In its letter dated July 30, 2003, the applicant provided the following response to RAI B2.1.3-3 items (a) and (b):

> Examinations of the containment liner will be performed at Ginna Station in accordance with the requirements of ASME Section XI, Subsection IWE, Paragraph IWE-3512. Ultrasonic (UT) thickness measurements that reveal material losses exceeding 10% of the nominal containment liner wall thickness, or material loss that is projected to exceed 10% of the nominal containment liner wall thickness prior to the next examination, will be documented. Such areas may be accepted by engineering evaluation or corrected by repair or replacement in accordance with Paragraph IWE-3122. If either the thickness of the liner is reduced by no more than 10% of the nominal plate thickness or the reduced thickness can be shown by analysis to satisfy the minimum design requirements, then such areas are acceptable by engineering evaluation.
>
> The area of the liner exhibiting degradation that was discovered during previous inspections will be re-examined in 2005 and thereafter on a three-year frequency. The minimum required thickness of the containment liner at Ginna Station has been determined by engineering analysis (and documented in EWR 5190) to be 0.281". Repair activities to restore the liner to its nominal thickness will be taken when the liner thickness reaches .300", or is expected to reach .300" before the next scheduled examination.

The staff considers the applicant's acceptance criterion for restoring the liner to its nominal thickness reasonable and acceptable. Moreover, the commitment (reference item 28 in Appendix A to this SER) to reexamine the liner, in the year 2005, will confirm if the corrective actions taken in the past examinations are effective in preventing further degradation of the containment liner.

In its clarification, dated July 11, 2003, the applicant addressed item (c) as follows:

> One-third of the circumference of the moisture barrier at the interface between the containment basement floor and the liner plate was inspected during the refueling outage in 2000. The remaining two-thirds of the moisture barrier will be inspected during the 2005 refueling outage. During the 2005 refueling outage, a minimum of three additional 20-foot lengths of insulation will be removed and inspections (including visual inspections and UT thickness measurements) of the exposed liner plate will be performed. Two of the areas selected for inspection will be on each side of the region inspected in 2002 on the southeast side of the containment. The third area will be located on the northwest side. In addition, insulation will be removed at any locations requiring further investigation where the moisture barrier exhibits evidence of degradation due to cracking, separation or loss of seal. Visual inspections and UT thickness measurements of the liner plate will be performed in these areas.

The staff considers the applicant's process of examining the liner covered by the insulation reasonable and acceptable because the process will identify any significant degradation in the most suspect areas and would initiate further investigations of the insulation-covered liner areas.

In RAI B2.1.3-4, the staff requested the applicant to provide information regarding its choice among the options for performing Type C testing during the period of extended operation. In its response, dated May 23, 2003, the applicant stated the following:

> Ginna Station containment isolation valves are currently tested under 10 CFR 50, Appendix J, Type C, Option B, as required by Technical Specification 5.5.15. This testing methodology will be maintained during the period of extended operation.

The staff finds the 10 CFR Part 50, Appendix J, Type C, Option B method adopted by the applicant acceptable based on the description of the implementation of 10 CFR Part 50, Appendix J, Option B in the LRA and the response to RAI B2.1.3-5. The staff finds the process used by the applicant for leak rate testing of containment acceptable.

In RAI B2.1.3-5, the staff pointed out that Section A2.1.3 of Appendix A (UFSAR Supplement) to the LRA summarized the content of the IWE and IWL AMP. However, it did not include the containment leak rate testing (i.e., GALL Report Section XI.S4) as part of the AMP. The applicant was requested to provide information regarding the inclusion of this aspect of the AMP in the UFSAR Supplement.

In its response, dated May 23, 2003, the applicant agreed that Section A2.1.3 of Appendix A to the LRA should have addressed Section XI.S4 of the GALL Report, and proposed the following addition to Section A2.1.3:

> This program also implements the requirements of 10 CFR 50, Appendix J. Containment leakage rates, in accordance with Option B of that regulation, through containment liner/welds, penetrations, and other openings are maintained within plant Technical Specification limits, or corrective actions are taken as required.

With this supplement, the staff considers that the scope of LRA Section A2.1.3 (UFSAR Supplement) provides an adequate description of the program and finds it to be acceptable, as required by 10 CFR 54.21(d).

3.5.2.3.1.3 Conclusions. On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with the GALL program. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.5.2.3.2 ASME Section XI, Subsection IWF Inservice Inspection Program

3.5.2.3.2.1 Summary of Technical Information in the Application. The applicant's inservice inspection program is discussed in LRA Section B2.1.4, "ASME Section XI, Subsection IWF Inservice Inspection." In its response to RAI B2.1.4-1, dated May 13, 2003, the applicant stated that the 10 program attributes have been reviewed and found to be consistent with the corresponding attributes in NUREG-1801, and that the program is consistent with the GALL Program XI.S3, "ASME Section XI, Subsection IWF," with no deviation. This is an existing program at Ginna.

The parameters monitored or inspected under the ASME Section XI, Subsection IWF Inservice Inspection Program include corrosion, deformation, misalignment, improper clearances, improper spring settings, damage to close-tolerance machined or sliding surfaces, and missing, detached, or loosened support items. Component bolting is visually inspected for indications of potential degradation, including loss of coating integrity, cracking, and obvious evidence of corrosion.

As part of its operating experience, the applicant stated that the ASME Section XI, Subsection IWF Inservice Inspection Program has been effective in managing the aging effects of Ginna ASME Class 1, 2, and 3 piping and MC supports. No significant age-related deterioration has been identified in the inspections performed.

In the LRA, the applicant concluded that the continued implementation of the ASME Section XI, Subsection IWF Inservice Inspection Program provides reasonable assurance that aging effects will be managed such that the intended functions of Class 1, 2, and 3 piping and MC supports will continue to perform their intended functions consistent with the CLB for the period of extended operation.

3.5.2.3.2.2 Staff Evaluation. In LRA Section B2.1.4, "ASME Section XI, Subsection IWF Inservice Inspection Program," the applicant described its AMP to manage the aging effects of Class 1, 2, and 3 piping and MC components and their associated supports. The LRA stated that this AMP is consistent with the GALL Program XI.S3, "ASME Section XI, Subsection IWF," with no deviations. The staff confirmed the applicant's claim of consistency during the AMP audit. In addition, the applicant provided, in its response, dated May 13, 2003, the detailed plant-specific operating experiences at Ginna. The staff determined that the applicant properly applied the GALL program to its facility. In addition, the staff reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program and found it to be acceptable, as required by 10 CFR 54.21(d).

3.5.2.3.2.3 Conclusions. On the basis of its review and audit of the applicant's program, the staff finds that this program is consistent with the GALL program. Therefore, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.5.2.3.3 Concrete Containment Tendon Prestress Program

3.5.2.3.3.1 Summary of Technical Information in the Application. The applicant described its Concrete Containment Tendon Prestress Program in Section B3.3 of the LRA. The LRA states that this program is consistent with GALL Program X.S1, "Concrete Containment Tendon Pre-Stress." The applicant credits this program with aging management of prestressing forces in prestressed concrete containments during the extended period of operation. The LRA also states that in order to ensure the adequacy of prestressing forces in prestressed concrete containments during the extended period of operation, the applicant performed a TLAA. The results of this analysis indicated that continued monitoring and potential retensioning of the containment tendons may be necessary to ensure that the prestressing forces remain above the minimum required value for all tendons. The applicant described the AMP as follows:

> The aging management program (AMP) consists of an assessment of the results of inspections performed in accordance with the requirements of Subsection IWL of the ASME Section XI Code (Reference 19), as supplemented by the requirements of 10 CFR 50.55a(b)(2)(ix) or (viii) in the later amendment of the regulation. The assessment related to the adequacy of the prestressing force will consist of the establishment of (1) acceptance criteria and (2) trend lines. The acceptance criteria are developed consistent with the methodology of NRC Regulatory Guide 1.35.1 and will normally consist of predicted lower limit (PLL) and the minimum required prestressing force, also called minimum required value (MRV). NRC Information Notice IN 99-10 provides guidance for constructing the trend line. The goal is to keep the trend line above the PLL because, as a result of any inspection performed in accordance with ASME Section XI, Subsection IWL, if the trend line crosses the PLL, the existing prestress in the containment could go below the MRV soon after the inspection and would not meet the requirements of 10 CFR 50.55a(b)(2)(ix)(B) or 10 CFR 50.55a(b)(2)(viii)(B).

The applicant provided a description of the 10 elements relevant to this program that are similar to the 10 elements contained in GALL Program X.S1, "Concrete Containment Tendon Prestress." These 10 elements are discussed in Section 3.5.2.3.3.2 of this SER.

Based on the above assertions, the applicant concluded that the Concrete Containment Tendon Prestress Program will manage the aging effect of loss of containment prestressing forces such that the intended functions of the tendon will be maintained during the period of extended operation.

3.5.2.3.3.2 Staff Evaluation. In addition to the review of Section B3.3 of the LRA, the staff reviewed the relevant information in Sections 2.4.1, 3.6, 4.5, 4.7.4, and B2.1.3 of the LRA. Based on its operating experience, the applicant foresees a need to have this program exclusively for managing the containment tendon prestress during the extended period of operation, in conjunction with the ISI program of B2.1.3 and TLAAs in Sections 4.5 and 4.7.4.

The staff evaluated the following 10 program elements:

Scope of Program. The program addresses the assessment of containment prestressing force. The staff finds this element acceptable, as it exclusively covers the aging management of containment prestressing force.

Preventive Actions. Maintaining the prestress above the MRV, as described in the program description above, will ensure that the structural and functional adequacy of the containment are maintained. The staff finds the Preventive Actions element acceptable because, as a result of implementing the program, the applicant ensures that the containment prestressing force will not go below what would be required for maintaining the containment intended function during the period of extended operation.

Parameters Monitored/Inspected. The parameters to be monitored are the containment prestressing forces, in accordance with requirements specified in Subsection IWL of Section XI of the ASME Code, as incorporated by reference in 10 CFR 50.55a. The staff finds the Parameters Monitored/Inspected element of the program acceptable as it will be in accordance with Subsection IWL of Section XI of the ASME Code, as incorporated by reference in 10 CFR 50.55a.

Detection of Aging Effects. This program detects the loss of containment prestressing forces. The staff finds the Detection of Aging Effects element acceptable because lower than expected prestressing force in the containment will trigger evaluations and corrective actions.

Monitoring and Trending. The estimated and measured prestressing forces are plotted against time and the PLL, MRV, and trending lines are developed for the period of extended operation. The staff finds the Monitoring and Trending element acceptable as it will trend the prestressing forces from the prior inspections and ensure that the trend line developed will not indicate prestressing forces in containment tendons lower than the MRV during the period of extended operation.

Acceptance Criteria. The prestressing force trend lines indicate that existing prestressing forces in the containment would not be below the MRVs prior to the next scheduled inspection, as required by 10 CFR 50.55a(b)(2)(ix)(B) or 10 CFR 50.55a(b)(2)(viii)(B). The staff finds the Acceptance Criteria element acceptable as it meets the requirement of 10 CFR 50.55a.

Corrective Actions. Corrective actions are implemented at the Ginna Station in accordance with the requirements of 10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” as described in the “Quality Assurance Program for Station Operation” (ND-QAP). Provisions for timely evaluation of adverse conditions and implementation of required corrective actions, including root cause determinations and prevention of recurrence, are included in the Ginna Station Corrective Action Program. This element is acceptable as it complies with the requirement for corrective action in Appendix B to 10 CFR Part 50.

Conformation Process. Confirmation of the effectiveness of the Concrete Containment Tendon Prestress Program is accomplished in accordance with the Ginna Station Corrective Action Program, site quality assurance (QA) procedures, review and approval processes, and administrative controls which are implemented in accordance with the requirements of Appendix B to 10 CFR Part 50. This element is acceptable because it complies with the requirement for corrective action in Appendix B to 10 CFR Part 50.

Administrative Controls. The Ginna Station QA procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of Appendix B to 10 CFR Part 50, and will continue to be adequate for the period of extended operation. The staff finds the administrative controls to be in compliance with the requirements of Appendix B to 10 CFR Part 50, and, therefore, are acceptable.

Operating Experience. The Ginna Station retensioned 23 of the 160 vertical tendons 1000 hours after initial prestressing. Subsequent tests identified that tendon lift-off forces were generally lower than the predicted values. An investigation was started to determine the reason for the accelerated loss of lift-off forces. Prior to completing the investigation, the Ginna Station retensioned the 137 tendons that were not originally retensioned. The investigation concluded that stress relaxation of the tendon wires was the only significant cause for the lower-than-predicted tendon forces. To quantify these findings, RG&E initiated a tendon stress relaxation test program that was conducted at the Fritz Engineering Laboratory of Lehigh University. The TLAA for the evaluation of loss of prestress in containment tendons concluded that the initial retensioned set of 23 tendons should be retensioned prior to the end of the current licensing period to ensure that prestressing forces remain above the MRV during the period of extended operation. (See Section 4.5 of this SER for the staff's evaluation of the applicant's TLAA for loss of concrete containment prestress.)

The staff reviewed the UFSAR Supplement for the concrete containment tendon force in Section A3.5 of the UFSAR Supplement to determine whether it provides an adequate description of the program. The summary includes the information relative to containment tendon fatigue in Section A3.5.1 of the LRA, as well as the related information on containment tendon bellows fatigue found in Section A3.5.2 of the LRA. The staff's evaluation of these activities is discussed in the evaluation of TLAAs in Sections 4.5, 4.7.2, and 4.7.4 of this SER.

3.5.2.3.3.3 Conclusions. On the basis of its review and audit of the applicant's program, the staff finds that this program is consistent with the GALL program. Therefore, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.5.2.4 Aging Management Review of Plant-Specific Structures and Structural Components

In this section of the SER, the staff presents its review of the applicant's AMR for specific structures and structural components. To perform its evaluation, the staff reviewed the components listed in LRA Tables 2.4.1-1 through 2.4.2-12 to determine whether the applicant properly identified the applicable aging effects and AMPs needed to adequately manage these aging effects. This portion of the staff's review involved identifying the aging effects for each component, ensuring that each component was evaluated in the appropriate LRA AMR Table in Section 3, and ensuring that management of the aging effect was captured in the appropriate AMP. The results of the staff's review are provided below.

3.5.2.4.1 Containment

3.5.2.4.1.1 <u>Summary of Technical Information in the Application</u>. The AMR results for the containment structural components are presented in Tables 3.6-1 and 3.6-2 of the LRA. The applicant used the GALL Report format to present its AMR of containment components in LRA Table 3.6-1. In LRA Table 3.6-2, the applicant identified the component group designation along with its (1) material, (2) environment, (3) aging effect(s), and (4) AMP(s).

As described by the applicant in Section 2.4.1 of the LRA—

> The reactor Containment Structure is a reinforced-concrete, vertical right cylinder with a flat base and a hemispherical dome. The structure houses and supports safety-related equipment, provides radiation shielding, and provides a barrier against the release of radioactive nuclides. A welded steel liner is attached to the inside face of the concrete shell to ensure a high degree of leak tightness. The thickness of the liner in the cylinder and dome is 3/8-in. and in the base it is 1/4 in. The cylindrical reinforced-concrete walls are 3 ft 6 in. thick, and the concrete hemispherical dome is 2 ft 6 in. thick. The concrete base slab is 2 ft thick with an additional 2-ft-thick concrete fill over the bottom liner plate. The Containment Structure is 99 ft high to the spring line of the dome and has an inside diameter of 105 ft.
>
> The Containment Structure consists of a reinforced concrete cylinder post-tensioned in the vertical direction and reinforced circumferentially with mild steel deformed bars. The dome is hemispherical and constructed of reinforced concrete.
>
> A two-foot thick reinforced concrete base slab extends radially from the reactor cavity pit to the containment cylinder wall. Except for participation in anchoring the radial tension bars at the base of the cylinder, the base slab is not an integral part of the containment shell in this design. The base slab rests directly on rock, and the loads on base slab are those from the internal structures and equipment. Near the cylinder wall the slab thickens to 6 ft., and extends beneath the wall above the concrete ring beam. The base slab and ring beam supports the dome and cylinder walls. The ring beam rests directly on rock and is the location of the end anchorage for the rock anchors. No drainage or de-watering system is provided under the Containment Structure. The base of the cylinder is supported by a neoprene pad, which provides a hinge support at the base. The vertical post-tensioning system is anchored at the base of the cylinder to rock anchors. The rock anchors are post-tensioned and grouted, which ensures that the rock acts as an integral part of the containment.

The materials of construction for the containment structure, as shown in Table 2.4.1-1 of the LRA, are (1) steel, (2) concrete, (3) elastomers, (4) PVC, (5) bronze, and (6) epoxy resin. These materials are exposed to containment air, outdoor air, borated water, and a buried environment.

Aging Effects

The LRA identifies the following aging effects for the components comprising the containment structure:

- cracking, loss of material, change in material properties, and loss of bond for concrete components
- cracking for masonry block walls
- loss of sealant for elastomers exposed to an outdoor environment
- loss of sealant, cracking, and change in material properties for elastomers inside containment
- loss of material for carbon steel components
- loss of material for epoxy inside containment
- cumulative fatigue, cracking, and loss of material for steel containment penetrations
- loss of leak tightness for containment hatches
- loss of material for the bronze manual valves attached to the tendon fill port piping

Aging Management Programs

The LRA credits the following AMPs with managing the identified aging effects for the components comprising the containment structure:

- ASME Section XI, Subsections IWE and IWL Inservice Inspection Program
- Boric Acid Corrosion Prevention Program
- Concrete Containment Tendon Prestress Program
- Periodic Surveillance and Preventive Maintenance Program
- Structures Monitoring Program
- Systems Monitoring Program

A description of these AMPs is provided in Appendix B to the LRA. The applicant concluded that the effects of aging associated with the components comprising the containment structure will be adequately managed by these AMPs such that the intended functions will be maintained consistent with the CLB for the period of extended operation.

3.5.2.4.1.2 Staff Evaluation. In addition to Section 3.6 of the LRA, the staff reviewed the pertinent information provided in Section 2.4, "Scoping and Screening Results: Structures," as well as the applicable AMP descriptions provided in Appendix B to the LRA, to determine whether the aging effects for the components comprising the containment structure have been properly identified and will be adequately managed during 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 of the components comprising the containment structure at Ginna. 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 appropriateness of the AMPs that are credited with managing the identified aging effects for the components comprising the containment structure.

Aging Effects

Concrete. For containment concrete components, the applicant's AMR is consistent with the recommendations in the GALL Report. As such, the applicant has committed to manage cracking, change in material properties (including loss of bond), and loss of material for accessible containment concrete components. Further discussion of cracking due to settlement and change in material properties, as manifested by a reduction in foundation strength for containment concrete, can be found in Sections 3.5.2.2.1.2 and 3.5.2.2.1.3 of this SER.

The above aging effects for containment concrete components result from several different aging mechanisms, which are included in the GALL Report. In RAI 3.6-12, the staff noted that the concrete containment groups CV-C-BUR, EXT, and INT in LRA Table 2.4.1-1 do not link to entry 15 in AMR Table 3.6-1 of the LRA. Entry 15 in AMR Table 3.6-1 covers cracking due to freeze-thaw and reaction with aggregates through the Containment Inservice Inspection Program for concrete elements, including foundation, dome, and walls. In response to RAI 3.6-12, the applicant stated that the omission was due to a typographical error and that entry 15 in AMR Table 3.6-1 is applicable to the commodity groups CV-C-BUR, EXT, and INT. Because the applicant has acknowledged the missing link between the concrete containment groups and the appropriate AMR table entry, the staff finds the applicant's response to be acceptable.

For below-grade containment concrete components, the GALL Report recommends aging management only for an aggressive below-grade soil/ground water environment. Because ASME Section XI, Subsection IWL, exempts from examination those portions of the concrete containment that are inaccessible, the GALL Report recommends that a plant-specific AMP be developed for concrete that may be exposed to an aggressive below-grade soil/ground water environment. As stated previously in SER Sections 3.5.2.2.1.1 and 3.5.2.2.2.2, the applicant claimed, in LRA Table 3.6-1, that the below-grade environment is nonaggressive. However, because the applicant did not provide any ground water chemistry values (pH, sulfates, and chlorides) to support this claim, the staff requested, in RAI 3.6-4, that the applicant provide these values. In response to RAI 3.6-4, the applicant stated, "the most recent samples ranged between 6 and 8 ppm chloride, 20 to 40 ppm sulfate, and a pH of 7.0." Because these ground water chemistry values do not constitute an aggressive environment as specified in the GALL Report (pH less than 5.5, sulfates greater than 1500 ppm, chlorides greater than 500 ppm), the staff finds that the applicant's claim of a nonaggressive below-grade environment to be accurate.

Because the ground water chemistry values provided by the applicant indicate a nonaggressive environment for concrete components, a plant-specific AMP for below-grade concrete components is not warranted. However, 10 CFR 50.55a(b)(2)(ix) requires that the licensee evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. The staff's review of the applicant's ASME Section XI, Subsections IWE and IWL Inservice Inspection Program in SER Section 3.5.2.3.1 provides further discussion concerning the inspection of inaccessible containment concrete structures.

For masonry block walls inside the containment, the applicant identified cracking as an applicable aging effect and its Structures Monitoring Program to manage it. Industry experience has shown that masonry is susceptible to cracking and, therefore, the staff finds the applicant's identification of cracking as an aging effect to be managed for masonry block walls inside the containment to be acceptable.

Steel. Consistent with the GALL Report recommendations, the applicant identified loss of material for containment carbon steel structural components and cumulative fatigue, cracking, and loss of material as applicable aging effects for steel containment penetrations. The applicant also identified loss of leak tightness as an applicable aging effect for the moveable hatch and equipment hatch; however, the GALL Report also recommends the management of loss of material due to general corrosion for these containment hatches. In RAI 3.6-10, the staff requested that the applicant explain this omission. In response to RAI 3.6-10, the applicant stated that the omission was due to a typographical error and that entry 10 in AMR Table 3.6-1 is applicable to the containment hatches. Since the applicant has acknowledged the missing link between the containment hatches and the appropriate AMR table entry, the staff finds the applicant's response to be acceptable.

The GALL Report also recommends management for loss of prestress for containment tendons; however, the applicant did not identify this aging effect for the component group CV-SS(CS)—Tendons listed in LRA Table 2.4.1-1. In RAI 3.6-11, the staff requested that the applicant explain this omission. In response to RAI 3.6-11, the applicant stated that the omission was due to a typographical error and that entry 11 in AMR Table 3.6-1 is applicable to the containment tendons. Because the applicant has acknowledged the missing link between the containment tendons and the appropriate AMR table entry, the staff finds the applicant's response to be acceptable. Further discussion of the aging effect of loss of prestress for containment tendons is found is Section 4.5 of this SER.

In LRA Section 2.4.1, the applicant described a corrosion protection system for the containment tendons. The applicant stated that this corrosion protection system is needed because the tendons are unbonded (i.e., not in intimate and integral contact with the surrounding concrete). As such, the protection of the surrounding concrete, as an inhibitor of corrosion for the tendons, is lost and the additional protection provided by the corrosion protection system is needed. As described in Section 2.4.1 of the LRA, one element of the corrosion protection system is a cathodic protection system in which all tendons are connected to the liner and then to a copper grounding system which is completed by the addition of reference cells and anodes. From this system, a protective potential can be generated if the need for cathodic protection is indicated by the reference cells.

The staff noted that this cathodic protection system does not appear in the LRA Section 2.4.1-1 scoping tables and hence is not evaluated as part of the AMR in Section 3.6 for the containment structural components. As such, the staff requested in RAI 3.6-2 that the applicant explain this omission. In response to RAI 3.6-2, the applicant stated the following:

> As described in UFSAR section 3.8.1.4.3.4, Corrosion Protection, section dd, at the time of containment construction, Durichlor anodes were installed around the perimeter of the vessel. Protective current can be applied from these anodes and regulated as needed to maintain a protective potential if cathodic protection is found necessary by measurements from the reference cells.
> The system was a construction feature installed because of a lack of operating experience involving the particular tendon design. The architect/engineers recognized that if unforeseen problems developed in the future the tendon design precludes easy repairs. To date voltage measurements, now incorporated

> into the Structures Monitoring program, have not indicated the need to employ cathodic protection measures. The containment tendon cathodic protection system is not used (no currents are impressed on the tendons) and is not relied upon to manage tendon aging. Operating experience has not indicated a current or future need for impressed current cathodic protection.

Through the use of the cathodic protection system, the applicant is able to monitor gross changes (i.e., severe loss of material) in the condition of the containment liner, tendons, and rock anchors, which are all connected to the cathodic protection system. Although the applicant stated above that periodic voltage measurements are made as part of the Structures Monitoring Program, these voltage tests are not documented in the LRA. As such, the staff in subsequent communications with the applicant obtained a commitment (reference item 29 in Appendix A to this SER) from the applicant to incorporate the periodic voltage measurements, referenced above in response to RAI 3.6-2, in one of its license renewal AMPs. The applicant committed to use the Periodic Surveillance and Preventive Maintenance Program for the periodic voltage measurements. The applicant also included this commitment in its "List of Regulatory Commitments," and modified Sections A2.1.17 and B2.1.23 of the LRA to reflect this commitment.

For the steel containment liner, the applicant identified loss of material due to general corrosion as an applicable aging effect and, consistent with the GALL Report recommendations, proposed to use both the ASME Section XI, Subsections IWE and IWL Inservice Inspection and the Boric Acid Corrosion Programs to manage this aging effect. However, the GALL Report also recommends further evaluation for the embedded portion of the containment liner, if corrosion of the containment liner is significant. This additional step is necessary since Subsection IWE exempts from examination portions of the containment that are inaccessible, such as embedded or inaccessible portions of steel liners and steel containment shells, piping, and valves penetrating or attaching to the containment. To cover inaccessible areas, 10 CFR 50.55a(b)(2)(ix) requires that the licensee evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to inaccessible areas. Because the applicant did not adequately address, in LRA Table 3.6-1, the above criterion defined in the GALL Report regarding the need for further evaluation to manage the potential aging of the embedded liner, the staff requested further information in RAI 3.6-16. In response to RAI 3.6-16, the applicant stated the following:

> Review of plant-specific operating experience and recent maintenance and corrective action documents identified only one nonconforming condition at the moisture barrier (caulking) which protects the inaccessible portion of the Containment steel liner from corrosion. This condition was discovered during inservice inspections performed to meet the requirements of ASME Section XI, Subsection IWE in 2000. As discussed in the response to RAI B2.1.3-3, insulation was removed and the liner was exposed for visual inspection in two areas. Evidence of minor surface corrosion was present in the area with the nonconforming caulking detail. Ultrasonic thickness readings were taken in both areas, including locations above and along the interface between the liner and the Containment concrete floor. All measured values exceeded the minimum required thickness with considerable margin. The liner was cleaned, re-coated and the moisture barrier restored in accordance with original design specification requirements in both areas.
>
> As a result of this discovery, the configuration of the moisture barrier was inspected around the entire circumference of the Containment and verified to be intact with no visible gaps or discontinuities. Additional inspections of the liner were performed during the 2002 refueling outage. As discussed in the response to RAI B2.1.3-3, approximately 70 linear feet of the liner were exposed and ultrasonic thickness measurements taken at four different excavated areas below the floor level. These measurements verified that no loss of liner thickness had occurred at these locations. The exposed

> portion of the liner was again cleaned, re-coated, and the moisture barrier restored in accordance with original design specification requirements.
>
> Additional inspections of the moisture barrier and liner are planned during the second and third periods of the Fourth ISI interval, which commenced on January 1, 2000. The condition of the inaccessible portions of the Containment liner may be assessed by evaluation of the condition of the liner at the interface with the concrete floor. Therefore, inspections performed under the ASME Section XI, Subsections IWE/IWL ISI Program will provide reasonable assurance that aging effects for the inaccessible portions of the liner plate can be managed so that the liner plate will continue to perform its intended function consistent with the current licensing basis during the period of extended operation.

Because previous inspections of the inaccessible portions of the liner (behind the moisture barrier) revealed only minor degradation, and because additional inspections of both the moisture barrier and liner will take place under the applicant's ASME Section XI, Subsections IWE and IWL Inservice Inspection Program, the staff finds that the applicant has provided a reasonable basis for concluding that the aging of the containment liner behind the insulation and the moisture barrier will be adequately managed consistent with its CLB during the extended period of operation. As such, the staff considers RAI 3.6-16 closed. This topic is also discussed in Section 3.5.2.2.1.4 of this SER.

For stainless steel components that are exposed only to indoor containment air, the applicant did not identify any applicable aging effects. These stainless steel structural components include the refueling cavity and fuel transfer liners (including attachments).

Elastomers (gaskets, caulking, seals). Consistent with the GALL Report recommendations, the applicant identified loss of seal as an applicable aging effect for elastomers exposed to either indoor or outdoor air. In addition, for the interior elastomers, the applicant also identified cracking due to thermal stress, ultraviolet radiation, and ozone, as well as change in material properties due to thermal stress, as applicable aging effects.

In LRA Section 2.4.1, the applicant described a neoprene pad which provides a hinge support at the base of the containment cylinder wall. The applicant stated the following in LRA Section 2.4.1:

> The vertical post tensioning system is anchored at the base of the cylinder to rock anchors. The rock anchors are post-tensioned and grouted, which ensures that the rock acts as an integral part of the containment.
>
> The rock anchors resist vertical axial loads in the cylinder walls and thereby avoid the transfer of vertical shear to the base slab. A sufficient physical separation is provided between wall and base slab to ensure that there is no transfer of vertical reaction to the base slab. A hinge is developed at the base of the containment cylinder by supporting the wall vertically on a series of elastomer bearing pads and anchoring the wall horizontally into the base slab with radial, high-strength steel tension bars. The tension bars resist the radial shear at the base of the containment cylinder and transfer this force as radial compression into the thickened portion of the base slab and ring beam, and thence, as a lateral load, onto the rock outboard of the ring beam and base slab.

The staff noted that these elastomer bearing pads do not appear in the LRA Section 2.4.1-1 scoping tables and hence are not evaluated as part of the AMR in Section 3.6 for the containment structural components. As such, the staff requested, in RAI 3.6-1, that the applicant explain this omission and provide an evaluation of the containment support system, which includes the neoprene bearing pads, in order to ensure its (the support system's) ability to stay functional during the extended period of operation. In response to RAI 3.6-1, the applicant stated the following:

> The accessible portions of the unique containment support system at Ginna Station include the upper wall-tendon anchorage hardware and grease cans. The inaccessible portions of the support system include the neoprene bearing pads, radial tension rods, and rock-anchors.
>
> Each of the 160 vertical wall tendons, consisting of 90, ¼ inch diameter wire bundles is connected at the base of the containment wall to another 90-wire tendon that is anchored by grouting into a 6-inch diameter hole drilled 43 feet into the base rock. These rock anchors were prestressed prior to construction of the containment. The functionality of this unique support system is monitored for structural adequacy by periodic tendon surveillance lift-off tests performed under plant procedure PT 27.2, "Tendon Surveillance Program." This procedure requires measurement of tendon lift-off forces, comparison of measured lift-off forces with predicted forces, evaluation of 6% overstress capability, inspection and testing of surveillance wire specimens, analytical testing of casing filler grease samples, and visual examination of tendon anchorage hardware and grease cans.
>
> The condition of other inaccessible components such as the neoprene pads and radial tension rods is inferred from visual examinations of the accessible portions of the containment structure such as the ring beam and containment wall surfaces performed under the ASME Section XI, Subsection IWE/IWL Program and the Structures Monitoring Program.

The staff recognizes that the applicant is aggressive in performing tendon inspections and that the tendon inspections provide a certain degree of confidence in the integrity of the rock anchor system coupled to the tendons. However, it is the inaccessible components of the containment support system that will not be directly managed for the extended period of operation. Inspections performed in accordance with the requirements of Subsection IWL of Section XI of the ASME Code will not be able to detect problems with the (1) tendon bellows, (2) elastomer bearing pads, or (3) radial tension bars. Moreover, the areas of the containment where these components are located are below the ground water level, and the staff identified water-related problems around the elastomer bearing pads in the early 1990s. As such, the staff concludes that the applicant needs to develop an AMP (which should include periodic functional tests) to verify the functionality of the containment support system.

In subsequent discussions, in a letter dated July 30, 2003, the applicant committed to performing two SITs during the extended period of operation, one in 2009 and one in 2029 (reference item 27 in Appendix A to this SER). The SIT will be performed at the peak calculated pressure in order to demonstrate conformance with the expected behavior of the containment support system, located in the lower part of the containment. SIT measurements will consist of radial and vertical deformations and can be compared to similar measurements taken during previous SITs.
In addition, visual observations will be made during and after the tests. The comparison will allow the applicant to detect significant deviation from the expected behavior of the containment support system. The staff finds the commitment acceptable because as it would periodically verify the behavior of the lower portion of the containment. Evaluation of the test results would indicate if there is a gross change in the containment behavior that would suggest significant degradation of the inaccessible containment support system components. As such, RAI 3.6-1 is considered closed.

<u>Miscellaneous Materials (PVC, epoxy resin, bronze)</u>. For the polyvinyl chloride (PVC) plastic foam insulation panels, the applicant did not identify any applicable aging effects. For the epoxy resin used to encapsulate the exposed tendon fill port piping and the bronze manual valves attached to the tendon fill port piping, the applicant identified loss of material as an applicable aging effect.

Aging Management Programs

The LRA credits the following AMPs with managing the identified aging effects for the components comprising the containment structure:

- ASME Section XI, Subsections IWE and IWL Inservice Inspection Program
- Boric Acid Corrosion Program
- Concrete Containment Tendon Prestress Program
- Periodic Surveillance and Preventive Maintenance Program
- Structures Monitoring Program
- Systems Monitoring Program

With the exception of the ASME Section XI, Subsections IWE and IWL Inservice Inspection, Concrete Containment Tendon Prestress, and Structures Monitoring Programs, each of the above AMPs are credited with managing the aging of several components in several different structures and systems and, therefore, are considered common AMPs. The staff review of the common AMPs can be found in Section 3.0.3 of this SER. The staff review of the ASME Section XI, Subsections IWE and IWL Inservice Inspection, Concrete Containment Tendon Prestress, and Structures Monitoring Program can be found in Sections 3.5.2.3.1, 3.5.2.3.3, and 3.0.3.10, respectively, of this SER.

After evaluating the applicant's AMR for each of the components comprising the containment structure, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects. For those components identified in Table 3.6-1 of the LRA, the staff verified that the applicant credited the AMP recommended by the GALL Report. For the components identified in Table 3.6-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effects.

For many of the LRA Table 3.6-1 and 3.6-2 entries, in addition to the GALL-recommended AMP (i.e., the Structures Monitoring Program or ASME Section XI, Subsections IWE and IWL Inservice Inspection Program), the Periodic Surveillance and Preventive Maintenance Program is also listed. In RAI 3.6-6, the staff requested that the applicant clarify the relationship between the Periodic Surveillance and Preventive Maintenance Program and the other listed AMPs with respect to managing the aging effects identified for the components in LRA Tables 3.6-1 and 3.6-2.
In response to RAI 3.6-6, the applicant stated the following:

> In Table 3.6-1 the ASME Section XI, Subsections IWE & IWL ISI (Containment ISI) program and the Structures Monitoring program are referenced as the approved NUREG-1801 aging management programs for structural components and component supports. However, for certain components, the Periodic Surveillance and Preventive Maintenance (PSPM) program was also credited for managing the effects of aging because periodic inspections of these components are driven by repetitive tasks (reptasks) in the PSPM program. For example, the PSPM program is credited along with the Containment ISI program for managing the effects of aging for the Containment personnel airlock and equipment hatch [line numbers (4) and (5)] seals, gaskets and moisture barriers [line number (6)], and tendon and anchorage components [line number (14)]. An explanation for crediting the PSPM program is provided in the discussion column for these line numbers.

Because the Periodic Surveillance and Preventive Maintenance Program is credited in addition to the GALL-recommended programs and is not the sole AMP used for the inspections of the GALL components, the staff finds the applicant's approach to be acceptable. Inspection frequencies, acceptance criteria, and other AMP attributes used for the aging management of the GALL components are those of the GALL-recommended programs. The Periodic Surveillance and Preventive Maintenance Program is used only as the vehicle under which the actual inspections are undertaken. The staff considers RAI 3.6-6 closed.

3.5.2.4.1.3 Conclusions. The staff has reviewed the information in Sections 2.4 and 3.6 of the LRA, as well as the applicable AMP descriptions in Appendix B to the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the components comprising the containment structure will be adequately managed so that there is reasonable assurance that these components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.5.2.4.2 Other Structures

3.5.2.4.2.1 Summary of Technical Information in the Application. The AMR results for other structures are presented in Tables 3.6-1 and 3.6-2 of the LRA. The applicant used the GALL Report format to present its AMR of structural components in LRA Table 3.6-1. In LRA Table 3.6-2, the applicant identified the component group designation along with its (1) material, (2) environment, (3) aging effect(s), and (4) AMP(s). The structural components listed in Tables 3.6-1 through 3.6-2 of the LRA are in the following structures:

- auxiliary building
- intermediate building
- turbine building
- diesel building
- control building
- all volatile water building
- screen house building
- standby auxiliary feedwater building
- service building
- cable tunnel
- essential yard structures

A brief description of each of the above structures is provided in Sections 2.4.2.1 through 2.4.2.11 of the LRA. The materials of construction identified in the LRA for each of the above structures are (1) concrete, including masonry, (2) steel, (3) aluminum, (4) elastomers, and (5) miscellaneous materials, such as glass, roofing, lead, rock, and cast iron. These materials are exposed to outdoor, buried, indoor not-air-conditioned, borated water, and raw water environments.

Aging Effects

Tables 3.6-1 and 3.6-2 of the LRA identify the following applicable aging effects for components in structures outside the containment:

- loss of material

- change in material properties
- cracking
- loss of seal or leak tightness
- loss of prestress
- loss of bond
- loss of form

Aging Management Programs

Tables 3.6-1 and 3.6-2 of the LRA credit the following AMPs with managing the identified aging effects for the components in structures outside the containment:

- Boric Acid Corrosion Program
- Periodic Surveillance and Preventive Maintenance Program
- Structures Monitoring Program
- Systems Monitoring Program
- Water Chemistry Control Program

A description of these AMPs is provided in Appendix B to the LRA. The applicant concluded 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 functions will be maintained consistent with the CLB for the period of extended operation.

3.5.2.4.2.2 Staff Evaluation. In addition to Section 3.6 of the LRA, the staff reviewed the pertinent information provided in Section 2.4, "Scoping and Screening Results—Structures," and the applicable AMP descriptions provided in Appendix B to the LRA to determine whether the aging effects for components in structures outside the containment have been properly identified and will be adequately managed during 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 of structures outside the containment at Ginna. 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 appropriateness of the AMPs that are credited with managing the identified aging effects for the components in structures outside the containment.

Aging Effects

Concrete. For concrete components in structures outside the containment, the applicant's AMR is consistent with the recommendations in the GALL Report. As such, the applicant has committed to manage cracking, change in material properties (including loss of bond), and loss of material for concrete structural components that are accessible. Section 3.5.2.2.2.1 of this SER provides further detail on the applicant's aging management of concrete components in structures outside the containment.

For below-grade concrete structural components, the GALL Report recommends aging management only for an aggressive below-grade soil/ground water environment. As previously stated in Section 3.5.2.2.2.2 of this SER, the applicant addressed the above criterion, defined in the GALL Report, in row entry 3.6.1.17 of LRA Table 3.6-1. Entry 17 of LRA Table 3.6-1 states the following:

> Inaccessible wall and concrete foundations are considered in the Structures Monitoring Program. Results of inspections for accessible concrete are evaluated and, if aging effects are noted, the Structures Monitoring Program evaluates the symptom and possible causes with respect to inaccessible areas. The Structures Monitoring Program requires periodic monitoring of ground water to verify chemistry remains non-aggressive. Concrete degradation in air due to aggressive rainwater is insignificant and the below-grade/lake water environment is non-aggressive. Additionally, recent structural inspections revealed no evidence of degradation owing to aggressive chemical attack; therefore, degradation due to chemical attack is not a probable aging effect at Ginna Station.
> The concrete at Ginna Station was designed in accordance with ACI 301-66 or ACI 318-63. ACI 301-66 refers to ACI 318 for concrete reinforcement. Designing concrete to ACI 318 also provides for sufficient concrete cover over embedded steel to provide ample corrosion protection. Chemical analyses performed on the rock and groundwater indicate these environments are non-aggressive. Since the embedded steel is not exposed to an environment which is considered aggressive, corrosion of embedded steel is not a probable aging effect at Ginna Station and has not been observed to date.

In RAI 3.6-4, the staff requested that the applicant provide the results of the Ground Water Monitoring Program, in terms of chlorides, sulfates, and pH of the ground water, in order for the staff to verify the applicant's claim of a nonaggressive below-grade environment. In response to RAI 3.6-4, the applicant stated, "the most recent samples ranged between 6 and 8 ppm chloride, 20 to 40 ppm sulfate, and a pH of 7.0." Because these ground water chemistry values do not constitute an aggressive environment as specified in the GALL Report (pH less than 5.5, sulfates greater than 1500 ppm, chlorides greater than 500 ppm), the staff finds that the applicant's claim of a nonaggressive below-grade environment to be accurate. As such, the further evaluation, as recommended by the GALL Report, is unnecessary. In addition, the applicant's Structures Monitoring Program requires periodic monitoring of ground/lake water to verify that the chemistry remains nonaggressive. Therefore, RAI 3.6-4 is considered closed.

For the buried concrete components in the screen house building that are exposed to flowing water, LRA Table 3.6.2.7 states that the aging effect of loss of material/abrasion due to cavitation is managed through periodic underwater inspections. These underwater inspections are part of the Periodic Surveillance and Preventive Maintenance Program.

Steel. Consistent with the recommendations of the GALL Report, the applicant identified loss of material as an applicable aging effect for carbon steel components in structures outside the containment. This includes carbon steel components in both indoor and outdoor environments, as well as carbon steel exposed to borated water leaks.

For buried carbon steel, such as the steel piles that support the cable tunnel, LRA Table 3.6.2.9 states the following:

> Buried carbon steel components can experience loss of material from corrosion. The Cable Tunnel is founded on steel piles driven to bedrock. These piles are inaccessible. The Structures Monitoring Program evaluates the effects of pile aging by monitoring the tunnel for signs of settlement which would indicate foundation degradation. Site operating experience on sheet piles, below grade on one side and exposed to air on the other, has shown that only minimal loss of material has occurred since construction. Additionally, inspections of opportunity performed on other buried carbon steel

components provide valuable information that may be used to infer the condition of inaccessible carbon steel piles. Thus, it can be concluded that the Structures Monitoring Program provides reasonable assurance that the aging effects of carbon steel piles will be managed through the period of extended operation.

The applicant's commitment to monitor the cable tunnel for evidence of settlement will provide sufficient aging management of the buried carbon steel foundation piles which support the tunnel. Any severe loss of material of these steel piles should be manifested through differential settlement of the cable tunnel.

Elastomers. For the structures outside containment, the applicant identified change in material properties and cracking as applicable aging effects in Table 3.6-2 of the LRA. The applicant credited the Structures Monitoring Program to manage these two aging effects for elastomeric material.

Miscellaneous Materials. For the structures outside containment, the miscellaneous component materials are (1) rock, (2) cast iron, (3) lead, (4) aluminum, and (5) architectural materials. For the rock revetment, which protects the plant from lake flooding, the applicant identified loss of form (erosion) as an applicable aging effect. For the cast iron manhole covers that are exposed to the weather, the applicant identified loss of material as an applicable aging effect. For the lead bricks and leaded glass used in the intermediate building as shielded enclosure, the applicant did not identify any applicable aging effects. Also, for the aluminum used in flood barriers and the aluminum conduit exposed to an indoor environment, the applicant did not identify any applicable aging effects. For the architectural materials (i.e., non-load-bearing building elements) such as building siding, builtup roof systems, and windows, the applicant identified hardening and shrinkage due to weathering, loss of material due to general corrosion, and cracking due to restraint, shrinkage, and creep as applicable aging effects.

Aging Management Programs

Tables 3.6-1and 3.6-2 of the LRA credit the following AMPs with managing the identified aging effects for the components in structures outside the containment:

- Boric Acid Corrosion Program
- Periodic Surveillance and Preventive Maintenance Program
- Structures Monitoring Program
- Systems Monitoring Program
- Water Chemistry Control Program

The applicant credits the above listed AMPs to manage the aging effects associated with structures and structural components outside the containment. Four of the AMPs (i.e., the Boric Acid Corrosion, Periodic Surveillance and Preventive Maintenance, Systems Monitoring, and Water Chemistry Control Programs) are credited to manage aging for components in other system groups (common AMPs), while the remaining AMP (Structures Monitoring Program) is credited with managing aging only for structures and structural components. The staff's evaluation of the common AMPs credited with managing aging in structures and structural components outside the containment is provided in Section 3.0.3 of this SER. The Structures Monitoring Program is evaluated in Section 3.0.3.10 of this SER.

After evaluating the applicant's AMR for each of the components comprising the structures other than containment, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects. For those components identified in Table 3.6-1 of the LRA, the staff verified that the applicant credited the AMP recommended by the GALL Report. For the components identified in Table 3.6-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effects.

In LRA Table 3.6.1.17, the applicant acknowledged that it used a different AMP than the GALL-recommended AMP for the Ginna water control structures, which include the circulating water system discharge canal, the canal's interface with the pump screen house, and a stone revetment which protects the site from surge flooding. The GALL-recommended AMP is RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants." The applicant instead uses the Structures Monitoring Program, in conjunction with the Periodic Surveillance and Preventive Maintenance Program, for the water control structures. In RAI 3.6-7, the staff requested that the applicant clarify this inconsistency with the GALL Report. In response, the applicant provided the following information:

> The Structures Monitoring Program and the Periodic Surveillance and Preventive Maintenance (PSPM) Program are inter-related, in that the PSPM program defines the periodicity of the inspections (repetitive tasks) to be performed under the Structures Monitoring program. As inspection results of the Structures Monitoring Program are analyzed, the frequency, or extent, of the inspections may be modified. These will be reflected in the PSPM program.
>
> It is important to note that Ginna's water control structure inspection program was developed by the Army Corps of Engineers during the Systematic Evaluation Program, SEP Topic III-3.C. Regulatory Guide 1.127 was issued well after Ginna Station was licensed, and we are not committed to its use. For example, the information requested by Regulatory Position C.1 was not compiled for the Ginna water control structures. Most of the information in Regulatory Position C.2 is also not applicable to Ginna, since these structures do not exist on the site. However, the information in C.2.a, C.2.b, and C.2.e can be applied at Ginna Station. Procedure M-92.2, "Inservice Inspection of Miscellaneous Water Control Structures at Ginna" uses RG 1.127 for guidance. We will evaluate the guidance provided in Regulatory Guide 1.127 to determine if more specific detail should be included in M-92.2.

Because the applicant uses the relevant portions of RG 1.127 for its aging management of the water control structures at Ginna, the staff finds the applicant's response to RAI 3.6-7 to be acceptable. RAI 3.6-7 is considered closed.

3.5.2.4.2.3 <u>Conclusions</u>. The staff has reviewed the information in Sections 2.4 and 3.6 of the LRA, the applicant's responses to the staff's RAIs, and the applicable AMP descriptions in Appendix B to the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the components in 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplements provide adequate program descriptions of the AMPs credited with managing aging in structures and structural components outside the containment to satisfy 10 CFR 54.21(d).

3.5.2.4.3 Component Supports

3.5.2.4.3.1 Summary of Technical Information in the Application. The AMR results for the component supports are presented in Tables 3.6-1 and 3.6-2 of the LRA. The applicant used the GALL Report format to present its AMR of the components in LRA Table 3.6-1. In LRA Table 3.6-2, the applicant identified the component group designation along with its (1) material, (2) environment, (3) aging effect(s), and (4) AMP(s).

Component supports are those components that provide support or enclosure for mechanical and electrical equipment. The component supports identified in LRA Section 2.4.2.12 include (1) expansion/grouted anchors; (2) electrical conduits and supports; (3) nuclear steam supply system (NSSS) pipe and supports; (4) vibration isolation equipment mounts; (5) seals and gaskets; (6) structural fasteners including high-strength fasteners; and (7) plates, channels, and support member beams.

The materials of construction for the component supports which are subject to an AMR include steel, aluminum, elastomers, grout, and wood. These materials are exposed to internal, external, raw and borated water, and embedded environments.

Aging Effects

Tables 3.6-1 and 3.6-2 of the LRA identify the following applicable aging effects for the component supports:

- loss of material
- cracking
- change in material properties
- loss of mechanical function
- reduction in concrete anchor capacity
- reduction/loss of isolation function

Aging Management Programs

Tables 3.6-1 and 3.6-2 of the LRA credit the following AMPs with managing the identified aging effects for the component supports:

- Bolting Integrity Program
- Boric Acid Corrosion Program
- ASME Section XI, Subsection IWF Inservice Inspection Program
- Periodic Surveillance and Preventive Maintenance Program
- Structures Monitoring Program

- Systems Monitoring Program

A description of these AMPs is provided in Appendix B to the LRA. The applicant concluded that the effects of aging associated with the components supports will be adequately managed by these AMPs such 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).

3.5.2.4.3.2 Staff Evaluation. In addition to Section 3.6 of the LRA, the staff reviewed the pertinent information provided in Section 2.4, "Scoping and Screening Results: Structures," and the applicable AMP descriptions provided in Appendix B to the LRA to determine whether the aging effects for the component supports had been properly identified and will be adequately managed during 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 of the component supports at Ginna. 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 appropriateness of the AMPs that are credited with managing the identified aging effects for the component supports.

Aging Effects

Steel. Consistent with the GALL Report, the applicant identified loss of material as an applicable aging effect for carbon steel component supports. For the carbon steel expansion/grouted anchors, the applicant identified reduction in anchor capacity as an applicable aging effect. For carbon steel component supports that are exposed to boric acid corrosion, the applicant also identified loss of material as an applicable aging effect. For the NSSS pipe and component supports, the applicant identified loss of material, as well as loss of mechanical function, as applicable aging effects. Finally, for high-strength structural fasteners, in addition to loss of material, the applicant also identified cracking due to SCC as an applicable aging effect. Each of the above aging effects for steel components is consistent with the GALL Report recommendations.

For stainless steel fasteners, plates, channel support members, and beams that are exposed to raw water, the applicant identified loss of material as an applicable aging effect.

Elastomers. Consistent with the GALL Report recommendations for elastomers used in cabinet door seals, gaskets, and as vibration equipment mounts, the applicant identified cracking, change in material properties, and reduction/loss of isolation function as applicable aging effects.

Aluminum. For aluminum electrical conduits and supports, the applicant did not identify any applicable aging effects; however, LRA Table 3.6.2-1 states that the Structures Monitoring Program will be used to inspect these components during the period of extended operation.

Concrete/Grout. For the grout used in the expansion/grouted anchors and for equipment foundations, the applicant identified reduction in anchor capacity as an applicable aging effect.

Wood. For the wood that is used as a platform base in a fan assembly and as an electrical cable spacer, the applicant did not identify any applicable aging effects; however, LRA Table 3.6.2-11 states that the Structures Monitoring Program will be used to inspect these components during the period of extended operation.

Aging Management Programs

Tables 3.6-1 and 3.6-2 of the LRA credit the following AMPs with managing the identified aging effects for the component supports:

- Bolting Integrity Program
- Boric Acid Corrosion Program
- ASME Section XI, Subsection IWF Inservice Inspection Program
- Periodic Surveillance and Preventive Maintenance Program
- Structures Monitoring Program
- Systems Monitoring Program

The applicant credits the above listed AMPs to manage the aging effects associated with the component supports. Four of the AMPs (i.e., the Bolting Integrity, Boric Acid Corrosion, Periodic Surveillance and Preventive Maintenance, and Systems Monitoring Programs) are credited to manage aging for components in other system groups (common AMPs), while the remaining AMPs (ASME Section XI, Subsection IWF Inservice Inspection and Structures Monitoring Programs) are credited with managing aging only for structures and structural components. The staff's evaluation of the common AMPs credited with managing aging in structures and structural components is provided in Section 3.0.3 of this SER. The Structures Monitoring Program is evaluated in Section 3.0.3.10 of this SER and the ASME Section XI, Subsection IWF Inservice Inspection Program is discussed in Section 3.5.2.3.2 of this SER.

After evaluating the applicant's AMR for each of the components comprising the structures other than containment, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects. For those components identified in Table 3.6-1 of the LRA, the staff verified that the applicant credited the AMP recommended by the GALL Report. For the components identified in Table 3.6-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effects.

For the aging management of carbon steel structural fasteners, the Structures Monitoring Program, Boric Acid Corrosion Program, and Bolting Integrity Program are all used. In RAI 3.6-8, the staff asked the applicant to describe the interaction of these three AMPs with regard to the aging management of structural fasteners. In response to RAI 3.6-8, the applicant stated the following:

> The Bolting Integrity Program consists of four separate aging management programs, in addition to the Boric Acid Corrosion Program and Structures Monitoring Program, which manage the effects of aging associated with bolting. These four programs are: (1) ASME Section XI, Subsections IWB, IWC, & IWD Inservice Inspection Program, (2) ASME Section XI, Subsection IWF Inservice Inspection Program, (3) Periodic Surveillance and Preventive Maintenance Program, and (4) Systems Monitoring Program. These six programs encompass the requirements for and attributes of the Bolting Integrity Program.

> Structural bolting is inspected under two separate aging management programs: Structures Monitoring Program and Boric Acid Monitoring Program.
>
> Visual inspections of bolting associated with structures within the scope of the Structures Monitoring Program are performed concurrent with the structure inspection. Structural bolting is inspected visually for evidence of corrosion, pitting, cracking, loose or missing hardware, evidence of boric acid buildup, physical damage or deformation, proper thread engagement of all nuts, proper bolt pattern, elongated or oversized bolt holes, proper washers, and proper stud alignment into the building structure.
>
> The scope of the Boric Acid Corrosion Program includes visual examinations of structures, components and associated bolting in all areas and spaces that could potentially be wetted and damaged by leaking boric acid. The program relies on visual inspections conducted during normal plant walkdowns and while performing maintenance work, as well as VT-2 inspections performed at operating pressure and temperature of systems that contain boric acid. The program incorporates the guidelines in NRC GL 88-05 and thereby provides for timely detection of leakage by observance of boric acid crystals deposits.
>
> The ASME Section XI, Subsections IWB, IWC, & IWD Inservice Inspection Program, the ASME Section XI, Subsection IWF Inservice Inspection Program, the Periodic Surveillance and Preventive Maintenance Program, and the Systems Monitoring Program are described in Sections B2.1.2, B2.1.4, B2.1.23, and B2.1.33, respectively, of the LRA.
>
> It is important to note that volumetric inspections (UT) are performed on high strength fasteners associated with Class 1 component supports under the ASME Section XI, Subsection IWF ISI Program.

The applicant’s aging management of bolting, as detailed in response to RAI 3.6-8, is consistent with the recommendations of the GALL Report. The only difference is that the applicant has combined several different AMPs under the Bolting Integrity Program to manage bolting. As such, RAI 3.6-8 is considered closed.

3.5.2.4.3.3 Conclusions. The staff has reviewed the information in Sections 2.4 and 3.6 of the LRA, the applicant’s responses to the staff’s RAIs, and the applicable AMP descriptions in Appendix B to the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the component supports will be adequately managed so that there is reasonable assurance that these components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.3 Evaluation Findings

On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and the AMPs credited with managing the aging effects for the structures and structural components, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation. The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement for Ginna provides an adequate program description of the AMPs credited with managing aging effects, as required by 10 CFR 54.21(d).

3.6 <u>Electrical and Instrumentation and Controls</u>

This section addresses the aging management of electrical and instrumentation and controls (I&C) components. The components have been divided into commodity groups as described in the following LRA sections:

- medium-voltage insulated cables and connectors (2.5.1)
- low-voltage insulated cables and connectors (2.5.1)
- electrical penetration assemblies (2.5.1)
- electrical phase bus (2.5.1)
- switchyard bus (2.5.1)
- transmission conductors (2.5.1)
- uninsulated ground conductors (2.5.1)
- high-voltage insulators (2.5.1)

In LRA Section 2.5.1, the applicant concluded that only the following commodity groups required an AMR:

- medium-voltage insulated cables and connectors
- low-voltage insulated cables and connectors
- electrical penetration assemblies
- electrical phase bus
- switchyard bus
- high-voltage insulators

3.6.1 Summary of Technical Information in the Application

In LRA Section 3.7, the applicant described its AMRs for the components within the electrical and I&C commodity groups at Ginna. The description of the electrical and I&C commodity groups can be found in LRA Section 2.5.

The results of the AMR of the electrical and I&C components are provided in LRA Section 3.7 and summarized in Table 3.7-1 and Table 3.7-2. Table 3.7-1 shows the aging management of system components evaluated in the GALL Report that are relied on for license renewal of the electrical and I&C components at Ginna. Table 3.7-2 contains the AMR results for those components that are not addressed in the GALL Report. A plant component is considered to be not addressed by the GALL Report if the component type is not evaluated in the GALL Report or it has a different material of construction or operating environment than evaluated in the GALL Report.

LRA Section 3.7 describes how the materials of construction of a component and the environments to which it is exposed were identified and then utilized in the AMRs. After the components requiring AMR were identified and grouped by materials of construction and environment, a review of industry and plant-specific operating experience was performed. The purpose of this review was to assure that all applicable aging effects were identified, and to evaluate the effectiveness of existing AMPs. This experience review was performed utilizing various industry and plant-specific programs and databases. Sources of industry operating experience included NRC generic publications (including information notices, circulars, bulletins, and generic letters), Institute of Nuclear Power Operators (INPO) significant operating event reports (SOERs), Electric Power Research Institute (EPRI) technical reports, and other information sources, such as the Sandia Aging Management Guidelines for Electrical Cable and Terminations, Westinghouse generic technical reports (GTRs), and the GALL Report. Plant-specific operating experience sources included semiannual and annual reports to the Atomic Energy Commission (AEC)/NRC, abnormal occurrence and licensee event reports (LERs), nonconformance reports (NCRs), corrective action reports (CARs), refueling, inspection, and overhaul reports (RIOs), inservice inspection reports, inspection discrepancy reports (IDRs), and action reports (ARs) from 1969 to the present. Information from these sources was compiled in various databases. Based upon the material of construction, the applicable environments, and operating experience, the potential aging effects requiring management for each of the components was identified and documented in Table 3.7-1 and Table 3.7-2.

3.6.2 Staff Evaluation

In Section 3.7 of the LRA, the applicant describes its AMR for electrical and I&C systems at Ginna. The staff reviewed LRA Section 3.7 to determine whether the applicant had provided sufficient information to demonstrate that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the period of extended operation, in accordance with the requirements of 10 CFR 54.21(a)(3), for electrical and I&C system components that are determined to be within the scope of license renewal and subject to an AMR.

The applicant referenced the GALL Report in its AMR. The staff has previously evaluated the adequacy of the aging management of electrical and I&C system components for license renewal as documented in the GALL Report. Thus, the staff did not repeat its review of the matters described in the GALL Report, except to ensure that the material presented in the LRA was applicable and consistent with GALL, and to verify that the applicant had identified the appropriate programs as described and evaluated in the GALL Report. The staff evaluated those aging management issues recommended for further evaluation in the GALL Report. The staff also reviewed aging management information submitted by the applicant that was different from that in the GALL Report or was not addressed in the GALL Report. Finally, the staff reviewed the UFSAR Supplement to ensure that it provided an adequate description of the programs credited with managing aging for the electrical and I&C system components.

Table 3.6-1 below provides a summary of the staff's evaluation of components, aging effects/mechanisms, and AMPs listed in LRA Section 3.7 that are addressed in the GALL Report.

Table 3.6-1 Staff Evaluation Table for Ginna Electrical Components Evaluated in the GALL Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Electrical equipment subject to 10 CFR 50.49 EQ requirements	Degradation due to various aging mechanisms	Environmental Qualification of Electrical Components	Environmental Qualification Program	Staff evaluation of TLAAs or EQ equipment is provided in Section 4.4

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Electrical cables and connections not subject to 10 CFR 50.49 EQ requirements	Embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced IR; electrical failure caused by thermal/thermoxidative degradation of organics; radiolysis and photolysis (UV-sensitive materials only) of organics; radiation-induced oxidation; moisture intrusion	Aging management program for electrical cables and connections not subject to 10 CFR 50.49 EQ requirements	Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program	Consistent with GALL (see Section 3.6.2.3.1 below)
Electrical cables used in instrumentation circuits not subject to 10 CFR 50.49 EQ requirements that are sensitive to reduction in conductor IR	Embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced IR; electrical failure caused by thermal/thermoxidative degradation of organics; radiation-induced oxidation; moisture intrusion	Aging management program for electrical cables used in instrumentation circuits not subject to 10 CFR 50.49 EQ requirements	Electrical Cables Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program	New AMP proposed by applicant in response to staff questions. Not consistent with GALL. Determined by staff to be an acceptable substitute for GALL program (see Section 3.6.2.3.2 below)
Inaccessible medium-voltage (2 kV to 15 kV) cables (e.g., installed in conduit or direct buried) not subject to 10 CFR 50.49 EQ requirements	Formation of water trees; localized damage leading to electrical failure (breakdown of insulation); water trees caused by moisture intrusion	Aging management program for inaccessible medium-voltage cables not subject to 10 CFR 50.49 EQ requirements	Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program	New AMP proposed by applicant in response to staff questions. Consistent with GALL (see section 3.6.2.4.3 below)
Electrical connectors not subject to 10 CFR 50.49 EQ requirements that are exposed to borated water leakage	Corrosion of connector contact surfaces caused by intrusion of borated water	Boric Acid Corrosion	Boric Acid Corrosion Program	Consistent with GALL (see Section 3.6.2.1 below and SER Section 3.0.3.4)

The staff's review of the electrical and I&C systems group for the Ginna LRA is contained within four sections of this SER. Section 3.6.2.1 presents the staff's review of components in the electrical and I&C systems that the applicant indicates are consistent with GALL and do not require further evaluation. Section 3.6.2.2 provides the staff's review of components in the electrical and I&C systems that the applicant indicates are consistent with GALL and for which GALL recommends further evaluation. Section 3.6.2.3 summarizes the staff's evaluation of the AMPs that are specific to the electric and I&C components. Section 3.6.2.4 contains an evaluation of the adequacy of aging management for components in the electrical and I&C systems group and includes an evaluation of components in the electrical and I&C systems that the applicant indicated are not in the GALL Report.

3.6.2.1 Aging Management Evaluations in the GALL Report That Are Relied on for License Renewal, Which Do Not Require Further Evaluation

For component groups evaluated in GALL for which the applicant has claimed consistency with GALL, and for which GALL does not recommend further evaluation, the staff toured plant spaces that the license renewal application indicated did not contain any license renewal functions to determine whether components were improperly eliminated from the scope of license renewal. The staff also identified several areas for which additional information or clarification was needed. The staff's evaluation of the applicant's responses to those RAIs are included in Sections 3.6.2.3.1 and 3.6.2.3.2 of this SER.

On the basis of its review, the staff has verified the applicant's claim of consistency with the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 50.21(a)(3).

3.6.2.2 Aging Management Evaluations in the GALL Report That Are Relied on for License Renewal, for Which GALL Recommends Further Evaluation

For component groups evaluated in the GALL Report for which the applicant has claimed consistency with GALL, and for which the GALL Report recommends further evaluation, the staff reviewed the applicant's evaluation to determine whether it adequately addressed the issues for which GALL recommended further evaluation. In addition, the staff sampled components in these groups to determine whether the plant-specific components contained in these GALL component groups were bounded by the GALL evaluation.

The GALL Report indicates that further evaluation should be performed for the electrical equipment subject to environmental qualification (EQ). Environmental qualification is a TLAA as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The staff's evaluation of this TLAA is documented in Section 4.4 of this SER, following the guidance in Section 4.4 of the SRP-LR.

3.6.2.3 Aging Management Programs for Electrical and Instrumentation and Controls Components

In SER Sections 3.6.2.1, the staff determined that the applicant's AMRs and associated AMPs will adequately manage component aging in the electrical and I&C systems. The applicant has included the appropriate Ginna plant-specific components in the appropriate GALL AMPs. The staff also reviewed information in the Ginna LRA and the applicant's responses to staff questions to ensure that (1) specific electrical and I&C system components were properly evaluated in the applicant's AMR, (2) electrical and I&C components requiring an AMP were put into an appropriate AMP, and (3) the applicant's claim of consistency with the GALL AMPs was accurate.

To perform its review, the staff reviewed the components listed in LRA Tables 2.5.2-1 through 2.5.14-1 to determine whether the applicant had properly identified the applicable AMRs and AMPs needed to adequately manage the aging effects for the components. This portion of the staff review involved identifying the aging effects for each component, ensuring that each aging effect was evaluated using the appropriate AMR in Section 3.7, and ensuring that management of the aging effect was captured in the appropriate AMP. The results of the staff's review are provided below in Section 3.6.2.4.

The staff also reviewed the UFSAR Supplements for the AMPs credited with managing aging in the electrical and I&C system components to determine whether the program descriptions adequately describe the programs.

The applicant credits six AMPs to manage the aging effects associated with electrical and I&C components. Three of the AMPs are credited to manage aging for components in other system groups (common AMPs), while the remaining three AMPs are credited with managing aging only for electrical and I&C components. The staff's evaluation of the common AMPs credited with managing aging in electrical and I&C components is provided in Section 3.0.3 of this SER. The common AMPs include the following programs:

- Boric Acid Corrosion Prevention Program (3.0.3.4)
- One-Time Inspection Program (3.0.3.7)
- Periodic Surveillance and Preventive Maintenance Program (3.0.3.8)

The staff's evaluation of the electrical and I&C component AMPs is provided below.

3.6.2.3.1 Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

3.6.2.3.1.1 Summary of Technical Information in the Application. The applicant's Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program is discussed in Item 2 of LRA Table 3.7-1 and in LRA Section B2.1.11. The applicant stated that the program is consistent with NUREG-1801 and will adequately manage the potential aging effects for these components. The applicant's analysis of material/environment combinations for normal plant environments indicates that a large majority of components have no aging effects that require management throughout the period of extended operation. Exceptions to this include PVC cables in containment subject to heating above ambient temperatures (self-heating) and cables installed in adverse localized equipment environments. However, due to plant-specific operating experience, all material/environment combinations will be included in the scope of the program using an encompassing approach.

The applicant provided the Ginna UFSAR Supplement for this program in LRA Section A2.1.9. It states the following:

> The program requires that cables and connections in accessible areas exposed to adverse localized environments caused by heat, radiation, or moisture are inspected on a periodic basis. Visual inspections for cable and connector jacket surface anomalies such as embrittlement, discoloration, cracking, and surface contamination are performed at least once every 10 years.

3.6.2.3.1.2 Staff Evaluation. In LRA Section B2.1.11, the applicant described its Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. The staff reviewed this AMP against the 10 program elements using the guidance in BTP RLSB-1 in Appendix A to the SRP-LR. The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program.

Under the Program Description element, the applicant stated that, "Selected cables and connections from accessible areas (the inspection sample) are inspected and represent, with reasonable assurance, all cables and connections in the adverse localized environments." Statements in other sections of the Ginna LRA, however, seem to indicate that all cables and connections within designated buildings/areas will be inspected. It was not clear to the staff whether the inspections under the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program will be limited to samples within adverse localized environments or whether all cables and connections within the designated buildings/areas will be inspected. If only a sample of all cables and connections are inspected, the applicant was asked to provide the technical basis for the sample, consistent with GALL Program XI.E1 attribute 3, under the Parameters Monitored/Inspected element. The applicant was also asked to indicate whether the sample will include the PVC cables in containment identified in Item 2 of Table 3.7-1.

The applicant provided responses to these staff questions in letters dated June 10, 2003, and July 11, 2003. The program described in B2.1.11 was revised, and the applicant stated that the scope does not limit the program to adverse localized environments but is structured to identify any such areas that may exist within the plant spaces containing electrical equipment subject to an AMR. The response indicated that because containment is a plant space within the scope of license renewal, the PVC cables in containment are addressed as part of the program. The response goes on to say that the AMP allows for a graded approach to examination based on operating experience and the specific environment. Therefore, it is not the applicant's intent to imply that all the accessible cable and connections within the identified plant building/areas will be visually inspected. When it is clear during the implementation of the program that a plant space contains no significant stressors and is within the analyzed assumptions for limiting materials of construction, then detailed inspections are not likely to occur. However, this does not eliminate the plant space from review for future inspections. A general inspection of the space will be performed in the future to verify that no changes have been made since the last inspection that could add significant stressors or adverse localized environments to the space. These responses resolve the staff's questions on this matter and are acceptable.

The revised Scope of Program attribute for this program states the following:

> This inspection program applies to accessible electrical cables and connections within the scope of license renewal that are installed or stored in the following plant buildings/areas (inspection areas):
>
> Auxiliary Building, Standby Auxiliary Feedwater Building, Control Building, All-Volatile-Treatment Building, Cable Tunnel, Diesel Generator Building, Intermediate Building, Reactor Containment, Service Building, Screen House, Turbine Building, Technical Support Center, Transformer Yard
>
> Plant buildings/areas not listed above that are used to store electrical cables and connections in the scope of license renewal for a specific, approved application (i.e., Appendix R equipment restoration) do not have adverse localized environments.

The Scope of Program attribute indicates that certain plant buildings/areas not specifically stated to be within scope and are used to store cables and connections for Appendix R equipment restoration do not have adverse localized environments. This statement was verified to be accurate during the Ginna license renewal AMP audit inspections. The inspector toured two warehouses where the licensee stored cables and connections for Appendix R equipment restoration and determined that the licensee controls the environment in the warehouses. The Appendix R electrical equipment is being stored on shelves above the ground. The warehouses also have a rodent prevention program.

The staff reviewed the applicant's revised UFSAR Supplement and found that it provided an adequate summary description of the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program, as required by 10 CFR 54.21(d).

3.6.2.3.1.3 Conclusions. On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with the GALL program. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.6.2.3.2 Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits

3.6.2.3.2.1 Summary of Technical Information in the Application. The Ginna LRA states, in Item 3 of Table 3.7-1, that cables used in low-level signal applications that are sensitive to reduction in insulation resistance (IR) (e.g., radiation monitoring and nuclear instrumentation) are not consistent with NUREG-1801. RG&E believes that invoking the GALL Program XI.E1, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," to manage the effects of aging in accessible non-EQ cable and connectors provides reasonable assurance that these SCs will perform their intended function during the period of extended operation. The aging effects of cable and connector insulation may have very long incubation periods. In essence, routine maintenance, calibration, and repair activities on the active components in an instrument loop initially work to mask indications of cable and cable and connector insulation degradation. Only after the active portions of a loop can no longer be adjusted to compensate for cable and connector degradation would the passive portions of the instrument loop become suspect. Surveillance provides meaningful information, but that information is primarily used to cause changes to the active portions of an instrument loop. The predominant cause of non-event-driven degradation in cable and connector insulation is thermal aging. External inspection of cables and connectors and their host environments that identifies the possibility of thermal aging long before instrument loop adjustments cannot compensate for current leakage. Because of this, RG&E feels that the only legitimate way to ensure the continued functioning of the long-lived passive components are those inspection activities performed under the GALL Program XI.E1, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements."

3.6.2.3.2.2 Staff Evaluation. Cables used in low-level signal applications that are sensitive to reduction in IR (e.g., radiation monitoring and nuclear instrumentation) were intended by the staff to be included in GALL Program XI.E2, "Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits." The applicant, instead, had originally included them in a program that is intended to be consistent with GALL Program XI.E1, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements." The XI.E1 program is a visual inspection program and the XI.E2 program is a calibration program. The applicant's discussion in Item 3 of LRA Table 3.7-1 indicates that the Ginna treatment of these circuits is not consistent with the GALL Report. It states that external inspection of cables and connectors and their host environments that identifies the possibility of thermal aging long before instrument loop adjustments cannot compensate for current leakage.

The staff asked the applicant to provide evidence or operational experience that supports this statement for non-EQ radiation monitoring and nuclear instrumentation cables. Such evidence could come from non-EQ radiation monitoring and nuclear instrumentation cables in the field or following accelerated aging tests. The staff was looking for examples of cables that exhibited visual signs of thermal aging, even though the current leakage of the circuits was small relative to the output signal level of the circuit. If this information were not available, the staff indicated that GALL Program XI.E2 should be adopted to ensure that the aging of non-EQ radiation monitoring and nuclear instrumentation cables is appropriately managed, consistent with the requirements in 10 CFR 54.21(a)(3).

Also with regard to this issue, the discussion in Item 3 of LRA Table 3.7-1 indicates that surveillance, such as calibration, may not be as good a choice as visual inspection to detect aging effects in low-signal-level instrumentation cable. It states that the predominant cause of non-event-driven degradation in cable and connector insulation is thermal aging.

The staff found that another potential cause of cable degradation is moisture. Chapter 3 of EPRI report TR-103834-P1-2, "Effects of Moisture on the Life of Power Plant Cables," identifies some water-related problems with instrumentation-type circuits. The *Operating Experience Summary* states that the first problem type, affecting the noise immunity of instrumentation circuits, was due to submergence degrading the jackets of instrumentation and coaxial cables. It would appear from this statement that activities, such as checking for increases in signal distortion level or other signal anomalies during the calibration process, could add additional benefit to the calibration surveillance and make it a more effective tool for detecting cable aging effects. This would be of particular benefit to the highly sensitive radiation monitoring and nuclear instrumentation circuits on the portion of the cable run that is located in conduit, which is subject to moisture intrusion and is not capable of being visually checked. The staff asked the applicant to address the moisture question.

The applicant provided its response to the staff questions on these issues in a letter dated June 10, 2003. The applicant stated the following:

> Based on the evidence presented in NUREG/CR-5772, RG&E has concluded that the mechanical aging effects are more pronounced than the electrical aging effects and therefore Ginna Station has determined that the visual inspection for mechanical aging effects will be more effective than attempting to implement a program such as that described in NUREG-1801 Section XI.E2.

The response discussed some of the findings in the NUREG, but concluded with the following:

> That being said, Ginna Station periodically performs insulation resistance testing on the Nuclear Instrumentation System circuits and High Range Radiation Monitor circuits. This testing is conducted based on plant specific operating experience and is used to identify gross changes in insulation resistance that could have an adverse impact on circuit operation. While changes in insulation resistance are sometimes caused by heat or radiation, moisture is also a stressor that may cause a reduction in insulation resistance. Ginna Station intends to continue periodic testing throughout the period of extended operation. Therefore, an aging management program based on the measurement of insulation resistance has been provided below. Ginna Station considers that this program more directly addresses the aging effect identified in NUREG-1801 Section XI.E2. Use of the insulation resistance testing does not preclude visual inspections of the accessible portions of these circuits as described in response to RAI 3.7-2.

The staff finds the combination of IR testing and visual inspection of the nuclear instrumentation system and high-range radiation monitor circuits to be an acceptable substitute for GALL Program XI.E2. The following program elements for the applicant's version of the Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program were provided in the applicant's response.

Program Description. Exposure of electrical cables to adverse localized environments caused by heat, radiation, or moisture can result in reduced IR. An adverse localized environment is defined as a condition in a limited plant area that is significantly more severe than the specified service condition for the circuit. 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 because it may contribute to inaccuracies in the instrument circuit.

The purpose of this AMP is to provide reasonable assurance that the intended function of\ high-voltage, low-signal circuits exposed to an adverse localized environment caused by heat, radiation, or moisture will be maintained consistent with the CLB throughout the period of extended operation.

In this AMP, an appropriate test, such as an IR will be used to identify the potential existence of a reduction in cable IR.

Scope of Program. This program applies to electrical cables used in circuits with sensitive, high-voltage, low-level signals, such as radiation monitoring and nuclear instrumentation, that are within the scope of license renewal. The staff finds this acceptable because it is consistent with the program scope for the circuits identified in GALL.

Preventive Actions. No actions are taken as part of this program to prevent or mitigate aging degradation. The staff concurs with this assessment and does not identify the need for any preventive actions associated with this program.

Parameters Monitored or Inspected. The parameters monitored include a loss of dielectric strength caused by thermal/thermoxidative degradation of organics, radiation-induced oxidation (radiolysis) of organics, or moisture intrusion. The staff finds that periodic monitoring of these parameters will adequately detect aging effects covered by this program. Therefore, the staff finds this acceptable.

Detection of Aging Effects. Cables will be tested at least once every 10 years. Testing may include IR, or other testing judged to be effective in determining cable insulation condition. Following issuance of a renewed operating license, the initial test will be completed before the end of the initial 40-year license term. The staff finds that testing is capable of detecting aging effects applicable to this program.

Monitoring and Trending. Trending actions are not included as part of this program because the ability to trend test results is dependent on the specific type of test chosen. Although not a requirement, test results that are trendable provide additional information on the rate of degradation. The staff finds that the monitoring and trending performed is consistent with that identified in GALL for these cables and is acceptable.

Acceptance Criteria. The acceptance criteria for each test is defined by the specific type of test performed and the specific cable tested. The staff finds that the acceptance criteria performed is consistent with that identified in GALL for these cables and is acceptable.

Corrective Actions. Corrective actions are implemented at the Ginna Station in accordance with the requirements of 10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," and ANSI N18.7-1976, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants," as committed to in Chapter 17 of the Ginna Station UFSAR and described in ND-QAP "Quality Assurance Program." Provisions for timely evaluation of adverse conditions and implementation of any corrective actions required, including root cause determinations and prevention of recurrence where appropriate, are included in the Corrective Action Program.

Corrective actions are implemented through the initiation of an action report in accordance with IP-CAP-1, "Abnormal Condition Tracking Initiation or Notification (Action) Report." Equipment deficiencies are corrected through the initiation of a work order in accordance with A-1603.2, "Work Order Initiation."

Confirmation Process. The confirmation process is part of the Corrective Action Program, which is implemented in accordance with the requirements of 10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," and ANSI N18.7-1976, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants," as committed to in Chapter 17 of the Ginna Station UFSAR. The aging management activities required by this program would also reveal any unsatisfactory conditions due to ineffective corrective action.

The “Abnormal Condition Tracking Initiation or Notification (Action) Report,” IP-CAP-1, includes provisions for tracking, coordinating, monitoring, reviewing, verifying, validating, and approving corrective actions to ensure that effective corrective actions are taken. Potentially adverse trends are also monitored through the action report process. The existence of an adverse trend due to recurring or repetitive adverse conditions will result in the initiation of an action report. A-1603.6, “Post-Maintenance/Modification Testing,” includes provisions for verifying the completion and effectiveness of corrective actions for equipment deficiencies. A-1603.6 provides guidance for the selection and documentation of post maintenance testing (PMT) or operability tests (OPTs), guidelines to ensure that equipment will perform its intended function prior to return to service and to ensure that the original equipment deficiency is corrected and a new deficiency has not been created.

Administrative Controls. The documents which implement the program are subject to administrative controls, including a formal review and approval process, and are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” and ANSI N18.7-1976, “Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants,” as committed to in Chapter 17 of the Ginna Station UFSAR.

Various procedures provide the required administrative controls, including a formal review and approval process, for procedures and other forms of administrative control documents.

“Procedures, Instructions and Guidelines,” ND-PRO, and “Procedure Control,” IP-PRO-3, provide guidance on procedures and other administrative control documents. IP-PRO-3 provides guidance on procedure hierarchy and classification, content and format, and preparation, revision, review, and approval of nuclear directives and all nuclear operating group procedures. “Procedure Adherence Requirements,” IP-PRO-4, establishes procedure usage and adherence requirements. IP-RDM-3, “Ginna Records,” delineates the system for review, submittal, receipt, processing, retrieval, and disposition of the Ginna Station records to meet, at a minimum, the Quality Assurance Program for Station Operation (QAPSO).

Operating Experience. Operating experience has shown that anomalies found during cable testing can be caused by degradation of the instrumentation circuit cable and are a possible indication of potential cable degradation. Gross changes in IR may be indicative of cable degradation caused by excessive heat, radiation, or moisture.

The staff reviewed the applicant’s revised UFSAR Supplement and found that it provided an adequate summary description of the applicant’s Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program, as required by 10 CFR 54.21(d).

3.6.2.3.2.3 Conclusions. On the basis of its review of the applicant’s program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are, in fact, consistent with the GALL program. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.6.2.3.3 Environmental Qualification Program

3.6.2.3.3.1 Summary of Technical Information in the Application. In Appendix B, Section B3.1, "Environmental Qualification Program," the applicant describes the aging management activities used to manage aging associated with the environmentally qualified equipment that is within the scope of license renewal and subject to an AMR. In Section 4.4 of the LRA, the applicant identifies the Environmental Qualification (EQ) Program as a time limited aging analyses (TLAA) for the purpose of license renewal. The applicant states that many of the EQ analyses are adequate under existing conditions and therefore could have been dispositioned per 10 CFR 54.21(c)(1)(i). However, the applicant was conservative and performed a confirmatory evaluation to verify that the assumptions in the existing analysis were adequate for the period of extended operation. Each TLAA was reviewed in accordance with 10 CFR 54.21(c)(1).

3.6.2.3.3.2 Staff Evaluation. The staff's evaluation of Ginna EQ Program focused on how the applicant demonstrated that the program managed the applicable aging effect through incorporation of the 10 elements of an effective aging management program as described in the Standard Review Plan for License Renewal (SRP-LR). The following is the staff's evaluation of each of the element for EQ equipment as submitted by the applicant in Section B3.1.

Scope of Program. The Ginna Station EQ Program applies to certain electrical components that are important to safety and could be exposed to harsh environment accident conditions, as defined in 10 CFR 50.49. The EQ program manages component, thermal, radiation and cyclical aging through the use of aging evaluations based on 10 CFR 50.49 (f). This is acceptable.

Preventive Actions. The EQ program actions that could be viewed as preventive actions include: (a) establishing service conditions for components to extend qualified life, and (b) requiring specific installation, inspection, monitoring or periodic maintenance actions to maintain component aging effects within the bounds of the qualification basis. Refurbishing, replacing or re-qualifying a component prior to exceeding that component's qualified life are preventive actions. This approach is consistent with 10 CFR 50.49 and 10 CFR 54.21(c)(1) and is therefore acceptable.

Parameters Monitored/Inspected. Monitoring or inspection of certain environmental conditions or component parameters may be used by Ginna to ensure that the components are within the bounds of its qualification basis, or as a means to modify the qualified life. This is acceptable as it is consistent with the requirements of 10 CFR 50.49 and 10 CFR 54.21(c)(1).

Detection of Aging Effects. The staff recognizes that, consistent with 10 CFR 50.49, the EQ Program is not used to detect ongoing aging. The applicant states that monitoring of environmental conditions such as temperature in the immediate vicinity of EQ equipment is used to ensure that the component is within the bounds of its qualification bases, or as a means to modify the qualified life. This is acceptable as it is consistent with the requirements of 10 CFR 50.49.

Monitoring and Trending. The applicant states that the Ginna EQ Program includes monitoring how long qualified components have been installed, how often they are operated/energized, and what discrete environmental conditions such as temperature and radiation exist. Such monitoring is used to ensure that selected components are within the bounds of their qualified bases, or to modify the qualified life. Monitoring each EQ component is consistent with the requirements of 10 CFR 50.49 and 10 CFR 54.21(c)(1) and is, therefore, acceptable to the staff. The applicant did not identify any trending activities, and the staff does not see the need for the trending.

Acceptance Criteria. 10 CFR 50.49 acceptance criteria are that an inservice EQ component is maintained within the bounds of its qualification basis, including (a) its established qualified life and (b) qualification for the projected accident conditions. 10 CFR 50.49 requires refurbishment, replacement, or re-qualification prior to exceeding the qualified life of each installed device. Where monitoring has been used to modify a component qualified life, Ginna specific acceptance criteria for operating in those conditions were established. This is consistent with the requirements of 10 CFR 50.49 and 10 CFR 54.21(c)(1) and is, therefore, acceptable.

Corrective Actions. The applicant states that if an EQ component is found to be outside the bounds of its qualification basis, corrective actions are implemented in accordance with the requirements of 10 CFR 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," as described in the Ginna Quality Assurance Program for Station Operation (ND-QAP). When unexpected adverse conditions are identified during operational or maintenance activities that affect the environment of a qualified component, the affected EQ component is evaluated and appropriate corrective actions are taken, which may include changes to the qualification bases and conclusions. When an emerging industry aging issue is identified that affects the qualification of an EQ component, the affected component is evaluated and appropriate corrective actions are taken, which may also include changes to the qualification bases and conclusions. This is acceptable.

Confirmation Process. The applicant states that confirmation of the effectiveness of the Environmental Qualification Program is accomplished in accordance with the Ginna Corrective Action Program, the site QA procedures, review and approval processes and administrative controls, which are implemented in accordance with the requirements of 10 CFR 50, Appendix B, and therefore are acceptable.

Administrative Controls. The applicant states that the EQ programs is implemented through the use of station policy, directives, and procedures. The EQ program will continue to comply with 10 CFR 50.49 throughout the renewal period, including development and maintenance of qualification documentation demonstrating reasonable assurance that a component can perform required functions during harsh accident conditions. EQ program documents identify the applicable environmental conditions for the component locations. EQ program qualification files are maintained at the plant site in an auditable form for the duration of the installed life of the component. EQ program documentation is controlled under the station's quality assurance program. This is acceptable.

Operating Experience. The applicant states that as a result of 10 CFR 50.49, Ginna installed extensive new environmentally qualified electrical equipment, in accordance with the Division of Operating Reactor Guidelines. The type of equipment replaced or installed included transmitters, level switches, electrical cable, solenoid valves, connectors, splices, and Linear Variable Differential Transformers. Upgrades were also made to electrical motors, valve activators, and electrical penetrations. On the basis of this, the staff concludes that the EQ program can continue to be effective and therefore acceptable.

3.6.2.3.3.3 Conclusion. The staff has reviewed the information provided in Appendix B, Section B3.1, "Environmental Qualification Program," of the LRA. On the basis of the review of this information and the above evaluation the staff finds the EQ program provides assurance that compliance with 10 CFR 50.49 is maintained; and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this program and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.6.2.3.4 Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

3.6.2.3.4.1 Summary of Technical Information in the Application. The applicant provided a description of the Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program in a letter dated December 9, 2003, in response to Open Item 2.5-1. In Attachment 2 to this letter, the applicant described its AMP to manage aging effects in inaccessible medium voltage cables that are exposed to adverse localized environments caused by moisture while energized. The letter stated that this AMP is consistent with GALL AMP XI.E3, "Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements."

3.6.2.3.4.2 Staff Evaluation. The staff confirmed the applicant's claim of consistency of the AMP with the GALL program. In addition, for Ginna, the staff determined whether the applicant properly applied the GALL program to its facility. Furthermore, the staff reviewed the UFSAR Supplement and found that it provides an adequate description of the revised program.

3.6.2.3.4.3 Conclusions. On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are, in fact, consistent with the GALL program. The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR, such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.6.2.4 Aging Management of Plant-Specific Components

The following sections provide the results of the staff's evaluation of the adequacy of aging management for electrical and I&C system components.

3.6.2.4.1 Medium Voltage-Voltage Insulated Cables and Connectors

3.6.2.4.1.1 Summary of Technical Information in the Application. The description of the medium-voltage insulated cables and connectors commodity group can be found in Section 2.5.1 of this SER. LRA Tables 2.5.4-1, 2.5.6-1, and 2.5.8-1 identify the systems which contain this commodity group, as well as the passive function and aging management references for the commodity group. The aging effects and AMR for the components in this commodity group are provided in LRA Table 3.7-1, Items 2, 3, and 5.

Aging Effects

The LRA identified the following applicable aging effects for the medium-voltage insulated cables and connectors:

- electrical cables and connections not subject to 10 CFR 50.49 EQ requirements components (Table 3.7-1, Item 2)—embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced IR; electrical failure caused by thermal/thermoxidative degradation of organics; radiolysis and photolysis (ultraviolet (UV) sensitive materials only) of organics; radiation-induced oxidation; moisture intrusion

- electrical cables used in instrumentation circuits not subject to 10 CFR 50.49 EQ requirements that are sensitive to reduction in conductor IR components (Table 3.7-1, Item 3)— embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced IR; electrical failure caused by thermal/thermoxidative degradation of organics; radiation-induced oxidation; moisture intrusion

- electrical connectors not subject to 10 CFR 50.49 EQ requirements that are exposed to borated water leakage components (Table 3.7-1, Item 5)—corrosion of connector contact surfaces caused by intrusion of borated water

Aging Management Programs

The LRA credits the following AMPs with managing the identified aging effects for the medium-voltage insulated cables and connectors:

- electrical cables and connections not subject to 10 CFR 50.49 EQ requirements components (Table 3.7-1, Item 2)—Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program

- electrical connectors not subject to 10 CFR 50.49 EQ requirements that are exposed to borated water leakage components (Table 3.7-1, Item 5)—Boric Acid Corrosion Program

3.6.2.4.1.2 Staff Evaluation. This section provides the results of the staff's evaluation of the applicant's AMR for the aging effects and the AMPs credited with managing them in medium-voltage insulated cables and connectors. The staff also reviewed the applicable UFSAR Supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects

- electrical cables and connections not subject to 10 CFR 50.49 EQ requirements components (Table 3.7-1, Item 2)

The aging effects identified for the components in LRA Table 3.7-1, Item 2 (electrical cables and connections not subject to 10 CFR 50.49 EQ requirements components), are consistent with the aging effects for the same components identified in the GALL Report. However, these aging effects only deal with the insulating portions of electrical cables and connections. They do not address the metallic portions (metallic clamps) of fuse holders. Fuse holders are identified in LRA Section 2.5.1 as part of the medium-voltage insulated cables and connections commodity group. The staff has developed interim staff guidance (ISG) for fuse holders. The ISG states that fuse holders (including both the insulation material and the metallic clamps) are subject to both an AMR and AMP for license renewal. It indicates that the AMP for fuse holders needs to identify and include fatigue, mechanical stress, vibration, chemical contamination, and corrosion as the metallic clamp aging stressors, if applicable. Neither the GALL Report nor the applicant's AMR currently address these metallic clamp stressors for fuse holders. The staff is currently working with NEI to develop an appropriate AMP for the fuse holder metallic clamps which will be incorporated into the GALL Report. The applicant provided the following response to a staff question on this subject in a letter dated May 23, 2003:

> Ginna Station has reviewed plant design documents and identified a limited number of fuse holder installations that are not part of a larger assembly. For several of the installations, a failure of the fuse (or fuse holder) does not prevent a safety function identified in 10CFR54.4(a)(1) from being accomplished. All fuse holder installations are enclosed to prevent mechanical damage and exposure to moisture or contaminants. No installations were identified that are used to routinely isolate the load device and therefore fatigue of the metallic portion of the fuse holder is considered unlikely. Additionally, none of the identified installations are subject to significant vibration, chemical contamination, or corrosion. Several of these installations were confirmed by visual inspection. Stress caused by thermal expansion and contraction of the metal is limited to the amount of current carried by the circuit and the frequency of load cycling. Only one power circuit with significant current capacity was identified that contained fuse holders that meet the intended scope of the interim staff guidance. These fuse holders were installed in 1996 as supplemental penetration protection for the pressurizer backup heater group. This heater group is infrequently energized, and would not be subject to significant thermal stress.
>
> Ginna Station reviewed entries in the corrective action program searching for deficiencies related to fuse holders and fuse clips, and determined that there have been a limited number of failures and no failures of such components that are not part of a larger assembly. The deficiencies identified are focused on only those locations such as motor control centers and switchgear where the fuses are removed for component maintenance. All such issues were readily identified during maintenance, and did not adversely impact component function.
>
> Ginna Station reviewed NUREG-1760 and Information Notices identified in the March 10, 2003 letter from the NRC to NEI. NUREG-1760 provides little evidence to suggest that the fuse holders at Ginna Station are subject to aging effects requiring management within the period of extended operation. Issues discussed in Information Notices do not identify a stressor applicable to the fuse installations at Ginna Station. All fuse holders identified at Ginna Station as meeting the intended scope of the interim staff guidance have been installed as part of plant modifications and are not original plant equipment. None of the fuse holders identified as within the scope of the ISG will have 40 years of accumulated life at the end of the period of extended operation.
>
> Based on a review of industry operating experience, plant specific operating experience, plant environments, and selected visual inspections, the fuses identified at Ginna Station that meet the intended scope of the interim staff guidance do not have aging effects requiring management within the period of extended operation. Ginna Station will continue to monitor industry and plant specific operating experience for aging effects that may be applicable to components subject to Aging Management Review and take steps as necessary to mitigate applicable aging effects as they arise.

The staff finds that the additional aging stressors evaluated by the applicant in its response for the metallic portions of the fuse holders are consistent with the stressors (fatigue, mechanical stress, vibration, chemical contamination, and corrosion) identified in the staff's fuse holder ISG.

- electrical cables used in instrumentation circuits not subject to 10 CFR 50.49 EQ requirements that are sensitive to reduction in conductor IR components (Table 3.7-1, Item 3)

The aging effects identified for the components in LRA Table 3.7-1, Item 3 (electrical cables used in instrumentation circuits not subject to 10 CFR 50.49 EQ requirements that are sensitive to reduction in conductor IR components), are consistent with the aging effects for the same components identified in the GALL Report.

- electrical connectors not subject to 10 CFR 50.49 EQ requirements that are exposed to borated water leakage components (Table 3.7-1, Item 5)

The aging effects identified for the components in LRA Table 3.7-1, Item 5 (electrical connectors not subject to 10 CFR 50.49 EQ requirements that are exposed to borated water leakage components), are consistent with the aging effects for the same components identified in the GALL Report.

On the basis of its review, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with medium voltage-voltage insulated cables and connectors.

Aging Management Programs

The applicant has credited the following AMPs to manage the aging effects described above for the medium-voltage insulated cables and connectors.

- Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Environmental Qualification Requirements Program

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program, identified for the components (electrical cables and connections not subject to 10 CFR 50.49 EQ requirements components) in LRA Table 3.7-1, Item 2, is consistent with the program for these same components identified in the GALL Report. However, both the programs address only the insulating portions of electrical cables and connections. They do not address the metallic portions (metallic clamps) of fuse holders. Fuse holders are identified in LRA Section 2.5.1 as part of the medium-voltage insulated cables and connections commodity group. The staff has developed interim staff guidance for fuse holders. The ISG states that fuse holders (including both the insulation material and the metallic clamps) are subject to both an AMR and AMP for license renewal. It indicates that the AMP for fuse holders needs to identify and include fatigue, mechanical stress, vibration, chemical contamination, and corrosion as metallic clamp aging stressors, if applicable. Neither the GALL Report nor the applicant's AMR currently address these metallic clamp stressors for fuse holders. The staff is currently working with NEI to develop an appropriate AMP for the fuse holder metallic clamps that will be incorporated into the GALL Report. The "Aging Effects" section above provides the applicant's response on this subject. Based on that response, the staff agrees that those fuse holders at Ginna that are not subject to fatigue, mechanical stress, vibration, chemical contamination, and corrosion do not fall within the scope of the staff fuse holder ISG and do not require an AMP for the metallic portion of the fuse holder. The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program is an acceptable AMP for the insulating portion of these fuse holders. With regard to the fuse holders that do fall within the scope of the staff's ISG, the applicant stated that none of the fuse holders identified as within the scope of the ISG will have 40 years of accumulated life at the end of the period of extended operation. The staff finds that, based on this fact, these fuse holders do not require an AMP for either the metallic portion or the insulating portion.

- Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program identified in the Ginna LRA for the nuclear instrumentation system and high-range radiation monitoring circuits' components is not consistent with the program for these same components identified in the GALL Report. This issue is evaluated above in Section 3.6.2.3.2.2 of this SER. The applicant committed to provide an AMP (i.e., the applicant's version of the Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program) that utilizes an IR test for these components (reference item 20 in Appendix A to this SER). The staff finds the combination of IR testing and visual inspection of the nuclear instrumentation system and high-range radiation monitor circuits to be an acceptable substitute for GALL Program XI.E2.

- Boric Acid Corrosion Program

The Boric Acid Corrosion program is a common AMP credited with managing components in other system groups, as well as electrical components (electrical connectors not subject to 10 CFR 50.49 EQ requirements that are exposed to borated water leakage components). The Boric Acid Corrosion program is evaluated in Section 3.0.3.4 of this SER.

3.6.2.4.1.3 Conclusions. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects, and the AMPs credited with managing them, for the medium-voltage insulated cables and connections, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement provides an adequate program description of the AMPs credited with managing aging in the medium-voltage insulated cables and connections, as required by 10 CFR 54.21(d).

3.6.2.4.2 Low-Voltage Insulated Cables and Connectors

3.6.2.4.2.1 Summary of Technical Information in the Application. The description of the low-voltage insulated cables and connectors commodity group can be found in Section 2.5.1 of this SER. LRA Tables 2.5.2-1, 2.5.3-1, 2.5.4-1, 2.5.5-1, 2.5.6-1, 2.5.7-1, 2.5.8-1, 2.5.9-1, 2.5.10-1, 2.5.11-1, 2.5.12-1, 2.5.13-1, and 2.5.14-1 identify the systems which contain this commodity group, as well as the passive function and aging management references for the commodity group. The aging effects and AMPs for the components in this commodity group are provided in LRA Table 3.7-1, Items 2, 3, and 5.

Aging Effects

The LRA identified the following applicable aging effects for the low voltage-voltage insulated cables and connectors:

- electrical cables and connections not subject to 10 CFR 50.49 EQ requirements components (Table 3.7-1, Item 2)—embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced IR; electrical failure caused by thermal/thermoxidative degradation of organics; radiolysis and photolysis (UV-sensitive materials only) of organics; radiation-induced oxidation; moisture intrusion

- electrical cables used in instrumentation circuits not subject to 10 CFR 50.49 EQ requirements that are sensitive to reduction in conductor IR components (Table 3.7-1, Item 3)— embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced IR; electrical failure caused by thermal/thermoxidative degradation of organics; radiation-induced oxidation; moisture intrusion

- electrical connectors not subject to 10 CFR 50.49 EQ requirements that are exposed to borated water leakage components (Table 3.7-1, Item 5)—corrosion of connector contact surfaces caused by intrusion of borated water

Aging Management Programs

The LRA credited the following AMPs with managing the identified aging effects for the low-voltage insulated cables and connectors:

- electrical cables and connections not subject to 10 CFR 50.49 EQ requirements components (Table 3.7-1, Item 2)—Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program

- electrical connectors not subject to 10 CFR 50.49 EQ requirements that are exposed to borated water leakage components (Table 3.7-1, Item 5)—Boric Acid Corrosion Program

3.6.2.4.2.2 Staff Evaluation. The staff's technical evaluation for the low-voltage insulated cables and connectors commodity group is identical to that provided for the medium-voltage insulated cables and connectors commodity group (see Section 3.6.2.4.1.2 of this SER).

3.6.2.4.2.3 Conclusions. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects, and the AMPs credited with managing the aging effects, for the low-voltage insulated cables and connections, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement provides an adequate program description of the AMPs credited with managing aging in the low-voltage insulated cables and connections, as required by 10 CFR 54.21(d).

3.6.2.4.3 Electrical Penetration Assemblies

3.6.2.4.3.1 Summary of Technical Information in the Application. The description of the electrical penetration assemblies commodity group can be found in Section 2.5.1 of this SER. LRA Section 2.5-1 states that all primary containment electrical penetration assemblies at the Ginna Station are included in the scope of the Environmental Qualification Program (10 CFR 50.49). The TLAA of electrical penetration assemblies is discussed in LRA Section 4.4.3.

3.6.2.4.3.2 Staff Evaluation. Section 2.5-1 of the LRA states that all primary containment electrical penetration assemblies at the Ginna Station are included in the scope of the Environmental Qualification Program (10 CFR 50.49). Components that are covered under the program are evaluated in Section 4.4 of this SER.

3.6.2.4.4 Electrical Phase Bus

3.6.2.4.4.1 Summary of Technical Information in the Application. The description of the electrical phase bus commodity group can be found in Section 2.5.1 of this SER. LRA Tables 2.5.4-1 and 2.5.5-1 identify the systems which contain this commodity group, as well as the passive function and aging management references for the commodity group. The aging effects and AMPs for the components in this commodity group are provided in LRA Table 3.7-2, Item 1.

Aging Effects

The LRA identified the following applicable aging effects for the electrical phase bus:

- electrical phase bus components (Table 3.7-2, Item 1)—Embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced IR; electrical failure caused by thermal/thermoxidative degradation of organics; moisture intrusion

Aging Management Programs

The LRA credited the following AMP with managing the identified aging effects for the electrical phase bus:

- Electrical phase bus components (Table 3.7-2, Item 1)—One-Time Inspection Program

3.6.2.4.4.2 Staff Evaluation. This section provides the results of the staff's evaluation of the applicant's AMR for the aging effects and the AMP credited with managing the aging effects in the electrical phase bus.

Aging Effects

- electrical phase bus components (Table 3.7-2, Item 1)

The discussion in LRA Table 3.7-2, Item 1, "Electrical Phase Bus," indicates that because a one-time inspection found no aging effects requiring management, no additional AMPs are required through the period of extended operation. The potential aging effects requiring management identified in Item 1 for the electrical phase bus appear to be associated with the organic insulating components of the phase bus, although the material column in the table only identifies porcelain insulators at Ginna. NRC IN 89-64 and a recent LRA identify bus duct insulation problems requiring management. IN 89-64 indicates that a combination of cracked insulation and accumulation of dust, debris, and moisture caused failure of the bus. Corrective actions included enhanced periodic inspections and cleaning of bus bars and their housings.

Item 1, “Electrical Phase Bus,” of Table 3.7-2 also does not address aging effects associated with the metallic electrical current carrying components of the phase bus. Oxidation and corrosion of the metallic components, or loosening of the fastener components (bolted bus connections), are examples of aging stressors that were not addressed. For example, oxidation of aluminum electrical connections can be problematic. The oxidation can create a high-resistance connection, resulting in additional heating at the connection, and further oxidation until failure occurs.

With regard to the fastener components, Reference 1 to Section 3.7 of the Ginna LRA, “Aging Management Guideline for Commercial Nuclear Power Plants,” on page 4-38 states the following:

> Circuits exposed to appreciable ohmic or ambient heating during operation may experience loosening related to the repeated cycling of connected loads or of the ambient temperature environment—repeated cycling in this fashion can produce loosening of the termination under ambient conditions, and may lead to high electrical resistance joints or eventual separation of the termination from the conductor.

Similarly, NRC IN 2000-14 identifies the phenomenon of “torque relaxation” of bus splice plate connecting bolts that can lead to overheating and arcing at the bus joint connection.

As a result of this background, the applicant was asked to provide a description of its AMP, in accordance with the requirements of 10 CFR 54.21(a)(3), used to detect aging effects associated with these aging stressors, or to provide justification as to why such a program is not needed.

The applicant provided its response in a letter dated July 16, 2003. The response provided the following description of the phase bus at Ginna:

> The phase bus at Ginna within the scope of license renewal is used to provide offsite power from the station auxiliary transformers to Bus 12A and Bus 12B. All phase bus discussed is non-segregated phase bus. The outdoor phase bus installed in the transformer yard was replaced in 1989 to support an offsite power reconfiguration. The outdoor phase bus (Unibus) contains copper conductors and uses an aluminum enclosure. It is non-ventilated, however it contains screened breathers on the bottom of the bus enclosure and electric space heaters for moisture control. Covers are sloped to shed water and gasketed to assist with water tightness. The design of the Unibus provides for overhanging metallic channels such that the gasket is not challenged by normal precipitation. This portion of the switchyard was installed in 1989 and will not have 40 years of operation at the end of the period of extended operation.
>
> The indoor phase bus (Westinghouse bus) is original plant construction and begins at the “link” separating the transformer yard from the control building identified on drawing LR33013-2409. This phase bus is constructed of aluminum conductors and uses a steel enclosure. This phase bus is non-ventilated and does not contain vents, breather screens, or electric space heaters.
>
> During the offsite power reconfiguration, the Westinghouse bus was cut and a splice box was built to transition to Unibus. These connection surfaces were constructed in 1989, and will have 40 years of operation upon the end of the license renewal period of extended operation.

The response goes on to address aging effects for the phase bus, the conductor heat rise and bolting stress, and a review of insulating materials and antioxidant. The response states that the Ginna Station performed a visual inspection of both the Unibus and the Westinghouse bus in 2002. The inspection confirmed the lack of moisture, significant contaminants, and insulation degradation.

The response further stated that the rated ampacity (A) of the 4-kV phase bus at Ginna is 3000 A. The normal loading of the phase bus within the scope of license renewal is less than 500 A under single offsite source operation. During the more common two offsite source operations, this current is split between the two buses. Under startup conditions, the conductors may experience a short-term increase of no more than 1250 A to carry station auxiliary loads. Therefore, under worst case loading conditions, the maximum current experienced by the phase bus is conservatively calculated at 1750 A. The applicant calculated service temperatures based on this loading and compared them to applicable ANSI standards and the calculated temperatures on the Diablo Canyon phase bus found in IN 2000-14. The Ginna temperatures are significantly lower. The applicant concluded that plastic deformation of connection hardware will not occur and stated that this is supported by Section 7.2.4 of EPRI TR-104213, "Bolted Joint Maintenance and Application Guide." The applicant stated that, based on analysis and industry guidance, bolt relaxation is not an aging effect requiring management at the Ginna Station.

The response provided a review of the insulating materials and antioxidants believed to have been used on the phase bus. Aging information was not readily available for the exact materials of construction, however, the service temperature was evaluated for all materials identified in EPRI 1003057, Table B-3, "License Renewal Electrical Handbook. The response states that, while the original AMR considered all Westinghouse splices to be tape wrapped based on installation instructions, photographs confirm that removable boots are used, and it is reasonable and conservative to consider these connections to be constructed of PVC. The applicant concludes all insulating materials, except the PVC boots, will perform their design function throughout the period of extended operation. The applicant committed to visual inspections of boots installed on Westinghouse buses to identify potential degradation due to thermal effects (reference item 25 in Appendix A to this SER). This inspection will be added to procedures for existing periodic switchgear inspection and preventive maintenance. Switchgear maintenance procedures and requirements for administrative controls will be referenced within the basis document for the Periodic Surveillance and Preventive Maintenance Program submitted in the LRA and modified by RAI responses. The Scope of Program attribute of this program will be modified to indicate that phase bus inspections are included within the program. Because inspections were performed in 2002, inspections will be required to be performed once prior to 2012, and will continue consistent with scheduled bus inspections and maintenance.
The program owner will be provided with the option of conducting inspections of 11A and 11B phase buses, instead of performing inspections of 12A and 12B phase buses, because, although not included within the scope of license renewal, 11A and 11B buses are subject to larger loading and higher resulting temperatures/stresses.

The applicant's response provided a review of potential oxidation of phase bus connections. It states that during the offsite power reconfiguration, the Westinghouse bus was cut and a splice box was built to transition to the Unibus. It assumed that Penetrox was used to connect the aluminum to the copper transition piece because the Westinghouse bus was not plated at the field cut/prepared end. In this location, the antioxidant material is credited with preventing oxidation of the connecting surfaces. Also considered in the response is that connection surfaces were constructed in 1989 and will not have 40 years of operation until the end of the license renewal period of extended operation.

The staff has reviewed the information in the response and finds that because the Unibus outdoor phase bus was installed in 1989 and will have only 40 years of operation at the end of the period of extended operation, it does not require an AMP.

With regard to the Westinghouse phase bus, the staff finds that visual inspection of the 12A and 12B phase bus under control of the Periodic Surveillance and Preventive Maintenance Program is acceptable for monitoring aging degradation of the phase bus insulating components. The staff does not agree that inspections of the 11A and 11B phase bus is an acceptable substitute for the 12A and 12B inspections. The staff believes the 11A and 11B phase bus inspections can be used to gain insight into potential future aging degradation of the 12A and 12B phase bus, but should not be used as a substitute for the 12A and 12B inspections due to potential dissimilarities in manufacture, assembly, and operation (faults, transients, surges, lightning, etc.).
The applicant should remove or modify this provision. In a letter dated September 16, 2003, the applicant stated that the provision for substituting inspections of the 11A and 11B phase bus will be removed from the Periodic Surveillance and Preventive Maintenance Program. This resolves this concern.

With regard to torque relaxation of the Westinghouse phase bus connecting bolts, the staff agrees that the conditions at Ginna are less severe than those found on the Diablo Canyon Unit 1 phase bus identified in IN 2000-14. The conditions at Diablo Canyon Unit 1, however, led to early failure of the phase bus in May 2000, less than 20 years following licensing of the plant in 1984. The staff reviewed the EPRI bolting guide referenced by the applicant. The guide provides general good bolting practices and guidelines for the use of threaded fasteners. Sections 6.12 and 7.0 provide guidance on proper assembly of electrical bolted connections. Section 8.2 provides guidance for inspection of electrical bolted joints. The staff believes it is unlikely that the Westinghouse phase bus at Ginna will be subject to the early failures experienced at Diablo Canyon. It is unclear, however, at what electrical loading profile a bolted electrical joint will not be subject to thermal relaxation over a 60-year period. The staff, therefore, believes the applicant should follow the inspection guidance in EPRI TR-104213 calling for bolted joint resistance testing (utilizing an ohm meter of appropriate magnitude) or should obtain the phase bus manufacturer’s (Westinghouse) endorsement that the testing is not required, given the electrical loading profile seen on these phase buses at Ginna. This is Open Item 3.6-1.

In a letter dated September 16, 2003, the applicant stated that it does not consider that the EPRI guidance intended for joint resistance tests is intended to be used for routine inspections.
The inspection guidance in Section 8.2 of EPRI TR-104213 states the following:

> Inspect bolted joints for evidence of overheating, signs of burning or discoloration and indications of loose bolts. The bolts should not be retorqued unless the joint requires service or the bolts are clearly loose. Verifying the torque is not recommended. The torque required to turn the fastener in the tightening direction (restart torque) is not a good indicator of the preload since the fastener is in service. Due to relaxation of the parts of the joint, the final loads are likely to be lower than the installed loads. However, this load reduction has little effect on the electrical conductivity or joint performance. Check the joint resistance of bolted joints using a low range ohm meter.

The applicant interprets this guidance to rely on inspection for “evidence of overheating, signs of burning or discoloration,” as the precursor to bus damage. When such precursor indications exist, then corrective actions would likely result in removal of the boot and performing inspections of the bolted connections. If degradation of the bolted connections is found, joint resistance measurements may be used to document “As-Found” conditions, as well as “As-Left” conditions following maintenance. When the suggested “check” is taken within the context of the entire paragraph, including the preceding sentence, the joint resistance test is interpreted only as a secondary test when there is some evidence that the joint may be degraded.

In considering appropriate inspections for the phase bus, the applicant stated that it reviewed operating experience directly related to IN 2000-14. This operating experience provides the industry with a description and photographs of a phase bus that had severely degraded PVC boots resulting from overheating conditions. However, the operating experience indicates that this condition was found during a planned inspection and does not indicate that the phase bus had failed.

Ultimately, the applicant committed (reference item 34 in Appendix A to this SER) to require joint resistance test to be performed when visual inspections of PVC boots or other materials of construction indicate that the joint may be overheating. This will be included in the program basis document for the Periodic Surveillance and Preventive Maintenance Program. The staff has reviewed the above information and concludes that performance of a joint resistance test when visual inspections of PVC boots indicates that the joint is overheating is acceptable. The above resolves Open Item 3.6-1.

With regard to the splice box that was constructed in 1989 to join the existing aluminum conductor Westinghouse phase bus to the new copper conductor Unibus phase bus, the applicant’s response stated that, “It is assumed that Penetrox was used to connect the aluminum to the copper transition piece because the Westinghouse bus was not plated at the field cut/prepared end.” The applicant should confirm that Penetrox, or another suitable antioxidant material, was indeed used on the electrical joint mating surfaces. Although the splice box will have only 40 years of operation upon the end of the license renewal period of extended operation, lack of a suitable antioxidant coating on the aluminum to copper mating surfaces could result in early failure of the electrical joint. This is Confirmatory Item 3.6-1.

In a letter dated December 9, 2003, the applicant provided a reply to Confirmatory Item 3.6-1. The reply states the following:

> The note “USE PENETROX BETWEEN EXISTING ALUMINUM AND NEW COPPER BUS BARS” on Drawing D-1800-013, Revision 2 (provided as Attachment C to 9/16/03 letter) was incorporated to note “as-built” conditions, i.e., those conditions actually verified in the field. This “as-built” note provides certainty in the conformance between design requirements and field conditions.

The staff reviewed Drawing D-1800-013, Revision 2, and found the note “Use Penetrox Between Existing Aluminum and New Copper Bus Bars.” The staff verified that the drawing indicates that the note was added in Revision 2 of the drawing to designate one of the “as built” conditions of the splice box. This resolves Confirmatory Item 3.6-1.

On the basis of its review, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the electrical phase bus.

Aging Management Programs

The applicant has credited the following AMPs to manage the aging effects described above for the electrical phase bus.

- One-Time Inspection Program

The One-Time Inspection Program is a common AMP credited to manage aging for components in other system groups, as well as for the electrical phase bus components. The One-Time Inspection Program is evaluated in Section 3.0.3.7 of this SER. The staff believes that the One-Time Inspection Program may not be sufficient to manage the aging effects of electrical phase bus components. The discussion above under the Aging Effects element identifies a past history of aging effects and potential aging effects associated with the electrical phase bus that require ongoing management.

- Periodic Surveillance and Preventive Maintenance Program

The Periodic Surveillance and Preventive Maintenance Program is a common AMP credited to manage aging for components in other system groups, as well as for the electrical phase bus components. The Periodic Surveillance and Preventive Maintenance Program is evaluated in Section 3.0.3.8 of this SER. The staff finds that visual inspection of the 12A and 12B phase bus under control of the Periodic Surveillance and Preventive Maintenance Program is acceptable for monitoring aging degradation of the Westinghouse phase bus components.

On the basis of its review, the staff finds that the applicant has credited the appropriate AMP to manage the aging effects for the materials and environments associated with the electrical phase buses. The UFSAR Supplement for the Periodic Surveillance and Preventive Maintenance Program is evaluated in Section 3.0.3.8 of this SER.

3.6.2.4.4.3 Conclusions. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects, and the AMPs credited with managing them, for the electrical phase bus, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The UFSAR Supplement for the Periodic Surveillance and Preventive Maintenance Program is evaluated in Section 3.0.3.8 of this SER.

3.6.2.4.5 Switchyard Bus

3.6.2.4.5.1 Summary of Technical Information in the Application. The description of the switchyard bus commodity group can be found in Section 2.5.1 of this SER. LRA Table 2.5.8-1 identifies the system which contains this commodity group, as well as the passive function and aging management references for the commodity group. The aging AMPs for the components in this commodity group are provided in LRA Table 3.7-2, Item 2.

Aging Effects

The LRA identified the following applicable aging effects for the switchyard bus:

- switchyard bus components (Table 3.7-2, Item 2)—loss of material due to corrosion leading to increased resistance

Aging Management Programs

The LRA did not credit an AMP for managing the identified aging effects of the switchyard bus.

3.6.2.4.5.2 Staff Evaluation. This section provides the results of the staff's evaluation of the applicant's AMR for the aging effects and the AMP credited with managing them in the switchyard bus.

Aging Effects

- switchyard bus components (Table 3.7-2, Item 2)

The discussion in LRA Table 3.7-2, Item 2, "Switchyard Bus," provides the following information:

> Rochester Gas and Electric's Energy Delivery Department performs inspection and maintenance of the Switchyard Bus components. Switchyard Bus components subject to aging management review contain materials that when exposed to plant operating environments could potentially lead to aging effects requiring management. Plant Operating Experience reviews have not identified any case where aging effects requiring management have developed however, evidence of aging effects may in fact be removed (masked) by ongoing routine Energy Delivery Department maintenance activities. That notwithstanding, the Energy Delivery Department inspections identify if the evidence of an aging mechanism is present and active and also provides the confirmation and verification of the absence of all types of aging effects. Indication of aging effects may be absent if the materials of construction and operational environment preclude an aging effect but, due to the long lead time necessary for some effects to manifest themselves, it is prudent to periodically assess the condition of SSCs regardless of the likelihood that a particular aging mechanism is applicable.
>
> Plant operating experience reviews show that the activities performed by the Energy Delivery Department on the Switchyard Buses are effective in managing Switchyard Bus components. The Maintenance Rule activities monitor the effectiveness of the Energy Delivery Department Activities by tracking system level performance indicators.

It appears that the activities performed by RG&E's Energy Delivery Department may be controlling the aging effects of the switchyard bus. If so, that program should be included under license renewal in accordance with the requirements of 10 CFR 54.21(a)(3). The applicant was, therefore, asked to describe the 10 attributes of the switchyard bus AMP consistent with the guidance provided in BTP RLSB-1 of the staff's license renewal SRP (NUREG-1800).

The aging effects identified by the staff in SER Section 3.6.2.4.4.2 for the metallic portions of the electrical phase bus might also be applicable to the switchyard bus. The applicant was, therefore, also asked to include a discussion of this topic in its response.

The applicant provided its response to the staff questions in a letter dated May 23, 2003, and in a subsequent letter dated July 11, 2003, responding to a followup staff clarification question. The response dated July 11, 2003, states the following:

> While there is no evidence that torque relaxation is an aging effect requiring management, there are several routine maintenance and inspection activities performed at Ginna Station as part of existing programs to ensure safe, reliable operation of the plant. The Preventative Maintenance and Periodic Surveillance program has been previously submitted as part of the License Renewal Application, and subsequently modified by RAI responses. This program includes periodic assessments of performance and condition monitoring activities and associated goals and preventive maintenance activities performed consistent with 10CFR50.65 requirements. This program credits the Equipment Diagnostic Monitoring program which includes the Infrared Thermography Program. As part of this program Ginna Station performs periodic thermography scans of onsite transformer yard components including transformers in the scope of license renewal (12A, 12B), as well as the upstream circuit breakers (52/75112, 52/76702), disconnect switches, and associated 34.5 kV switchyard bus. A review of a typical thermography image shows that normal temperature rise is less than 10°F above ambient, which confirms the initial assumption that temperatures would be minimal and torque relaxation of bolted connections is not an aging effect requiring management within the period of extended operation.
>
> Administrative controls will be implemented prior to the period of extended operation to ensure that thermographic inspections of 34.5 kV transformer yard components are performed at least once within each refueling cycle while components are energized. These controls will ensure that the inspections will not be canceled or deferred without sufficient analysis and justification. This is consistent with other aspects of the Periodic Surveillance and Preventative Maintenance Program as described in License Renewal Program Basis Document LR-PSPM-PROGPLAN. This program will be revised to clarify that the program includes thermographic inspections of selected components, including transformer yard components.

The staff finds that the use of thermography scans of the onsite transformer yard components, including the switchyard bus, is an acceptable means for monitoring potential aging degradation due to torque relaxation of the bolted electrical connections used in these components. These scans will be conducted under the control of the Periodic Surveillance and Preventive Maintenance Program.

On the basis of its review, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the switchyard bus.

<u>Aging Management Programs</u>

The applicant has credited the following AMPs to manage the aging effects described above for the switchyard bus.

- Periodic Surveillance and Preventive Maintenance Program

The LRA did not credit an AMP for managing the identified aging effects of the switchyard bus. However, as indicated above, in response to staff questions, the applicant has committed to the use of thermography scans of the onsite transformer yard components, including the switchyard bus (reference item 22 in Appendix A to this SER). These scans will be conducted under the control of the Periodic Surveillance and Preventive Maintenance Program. This program is reviewed in Section 3.0.3.8 of this SER.

On the basis of its review, the staff finds that the applicant has credited the appropriate AMP to manage the aging effects for the materials and environments associated with the switchyard bus.

3.6.2.4.5.3 Conclusions. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects, and the AMP credited with managing them, for the switchyard bus, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.4.6 High-Voltage Insulators

3.6.2.4.6.1 Summary of Technical Information in the Application. The description of the high-voltage insulators commodity group can be found in Section 2.5.1 of this SER. LRA Table 2.5.8-1 identifies the system which contains this commodity group, as well as the passive function and aging management references for the commodity group. The aging effects and AMP for the components in this commodity group are provided in LRA Table 3.7-2, Item 3.

Aging Effects

The LRA identified the following applicable aging effects for the high-voltage insulators:

- high-voltage insulator components (Table 3.7-2, Item 3)—cracks; loss of material due to corrosion; loss of dielectric strength leading to reduced IR

Aging Management Programs

The LRA did not credit an AMP for managing the identified aging effects of the high-voltage insulators.

3.6.2.4.8.2 Staff Evaluation. This section provides the results of the staff's evaluation of the applicant's AMR for the aging effects, and the AMP credited with managing them, in high-voltage insulators.

Aging Effects

- High-voltage insulator components (Table 3.7-2, Item 3)

The discussion in LRA Table 3.7-2, Item 3, "High-Voltage Insulators," is essentially identical to that provided in LRA Table 3.7-2, Item 2, "Switchyard Bus," identified in SER Section 3.6.2.4.5.2 above. Consistent with the switchyard bus issue, it appears that the activities performed by RG&E's Energy Delivery Department may be controlling the aging effects of the high-voltage insulators as well. If so, that program should be included under license renewal in accordance with the requirements of 10 CFR 54.21(a)(3). The applicant was, therefore, asked to describe the 10 attributes of the high-voltage insulators AMP consistent with the guidance provided in BTP RLSB-1 of the staff's license renewal SRP (NUREG-1800).

The applicant provided its response to the staff questions in a letter dated May 23, 2003, and in a subsequent letter dated July 11, 2003, responding to a followup staff clarification question. The response dated July 11, 2003, stated that an AMR had been performed for the high-voltage insulators within the scope of license renewal at the Ginna Station. The response provided the following paragraph based on this AMR.

> Various airborne materials such as dust, and industrial effluents can contaminate insulator surfaces. The buildup of surface contamination is gradual and is normally washed away by rain; the glazed insulator surface aids this contamination removal. Surface contamination can be a problem in areas where there are greater concentrations of airborne particles such as near facilities that discharge soot or near the seacoast where salt spray is prevalent. Ginna is located next to a fresh water lake, in a rural, non-industrial area with moderate rainfall where airborne contaminants are comparatively low. There are no facilities in the area that discharge airborne particles that could buildup on the insulators and cause flashover or otherwise adversely impact the intended function. Consequently, the rate of contamination buildup on the insulators is not significant, and would be washed away by normal precipitation if present. A review of industry and plant operating experience identified IN 93-95, Storm-Related Loss of Offsite Power Events Due to Salt Buildup on Switchyard Insulators. A review of IN 93-95 concluded that salt buildup is not a valid stressor for high-voltage insulators at Ginna Station. Therefore, surface contamination is not an aging effect requiring management for high-voltage insulators at Ginna. Visual inspections of the insulators provide confirmatory evidence for this conclusion.

The applicant followed this up with a discussion of the contamination aging mechanism.

> In this case, operating experience provides significant information about the aging mechanisms related to contamination of the high-voltage insulators. This degradation mechanism is one that could manifest itself over a short period of time (possibly one year) if conditions for such degradation exist. With more than 30 years of operating experience, a lack of contamination indicates that high-voltage insulators do not become contaminated at Ginna Station. At this time, there is no reason to believe that there will be a change in environment that could suddenly permit or contribute to insulator contamination. Therefore for this aging mechanism, operating experience and a lack of exhibited aging effects provides a strong basis to conclude that aging management for high-voltage insulators is not required.

The staff agrees with the applicant that, for this aging mechanism, operating experience and a lack of exhibited aging effects provide a basis to conclude that aging management for high-voltage insulators is not required. The staff therefore finds that, based on the applicant's discussion of its AMR performed on the high-voltage insulators, aging management of these insulators at Ginna is not required.

On the basis of its review, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with high-voltage insulator components.

<u>Aging Management Programs</u>

The LRA did not credit an AMP for managing the identified aging effects of the high-voltage insulators. However, as indicated above, the staff finds that, based on the applicant's discussion of its AMR performed on the high-voltage insulators, aging management of these insulators at Ginna is not required.

3.6.2.4.8.3 Conclusions. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects for the high-voltage insulators, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.3 Evaluation Findings

On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and the AMPs credited with managing the aging effects for the electrical and I&C system, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB during the period of extended operation. The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement for Ginna provides an adequate program description of the AMPs credited with managing aging effects, as required by 10 CFR 54.21(d).

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4. TIME-LIMITED AGING ANALYSES

4.1 Identification of Time-Limited Aging Analyses

This section addresses the identification of time-limited aging analyses (TLAAs). The applicant provided a list of TLAAs in LRA Sections 4.2 through 4.7. The staff's review of the TLAAs can be found in Sections 4.2 through 4.7 of this safety evaluation report (SER).

The TLAAs are certain plant-specific safety analyses that are based on an explicitly assumed 40-year plant life. Pursuant to Title 10, Section 54.21(c)(1), of the *Code of Federal Regulations* (10 CFR 54.21(c)(1)), the applicant for license renewal must provide a list of TLAAs, as defined in 10 CFR 54.3.

In addition, pursuant to 10 CFR 54.21(c)(2), an applicant must provide a list of plant-specific exemptions granted under 10 CFR 50.12 that are based on TLAAs. For any such exemptions, the applicant must provide an evaluation that justifies the continuation of the exemptions for the period of extended operation.

4.1.1 Summary of Technical Information in the Application

The applicant evaluated calculations for Ginna against the six criteria specified in 10 CFR 54.3 to identify the TLAAs. The applicant indicated that calculations that meet the six criteria were identified by searching the current licensing basis (CLB), which includes the updated final safety analysis report (UFSAR), design-basis documents (DBDs), previous license renewal applications (LRAs), technical specifications, NUREG-1800, and Nuclear Energy Institute (NEI) 95-10. The applicant listed the following TLAAs in Table 4.1-1 of the LRA:

- reactor vessel neutron embrittlement, including analyses for upper-shelf energy, pressurized thermal shock, and pressure/temperature limits
- metal fatigue, including ASME Class 1, reactor vessel underclad cracking, ANSI B31.1 piping, accumulator check valves, reactor vessel nozzle-to-vessel weld defect, and pressurizer fracture mechanics analysis
- environmental qualification of electrical equipment
- containment concrete tendon prestress
- containment liner plate and penetration fatigue
- containment liner stress
- containment tendon fatigue
- containment liner anchorage fatigue

- containment tendon bellows fatigue
- crane load cycle limit
- reactor coolant pump flywheel
- thermal aging embrittlement of cast austenitic stainless steel

Pursuant to 10 CFR 54.21(c)(2), the applicant stated that no exemptions granted under 10 CFR 50.12 that were based on a TLAA, as defined in 10 CFR 54.3, were identified.

4.1.2 Staff Evaluation

In LRA Section 4.1, the applicant identified the TLAAs applicable to Ginna and discussed exemptions based on them. The staff reviewed the information to determine whether the applicant provided adequate information to meet the requirements of 10 CFR 54.21(c)(1) and 10 CFR 54.21(c)(2).

As indicated by the applicant, TLAAs are defined in 10 CFR 54.3 as calculations and analyses that meet the following six criteria:

- involve systems, structures, and components within the scope of license renewal, as delineated in 10 CFR 54.4(a)
- consider the effects of aging
- involve time-limited assumptions defined by the current operating term (for example, 40 years)
- determined to be relevant by the applicant in making a safety determination
- involve conclusions, or provide the basis for conclusions, related to the capability of the system, structure, and component to perform its intended functions, as delineated in 10 CFR 54.4(b)
- contained or incorporated by reference in the current licensing basis

The applicant listed the TLAAs applicable to Ginna in Table 4.1-1 of the LRA. Tables 4.1-2 and 4.1-3 in NUREG-1800 identify potential TLAAs determined from the review of other LRAs. In request for additional information (RAI) 4.1-1, the staff requested that the applicant discuss whether there were any calculations or analyses at Ginna that addressed the topics listed in Tables 4.1-2 and 4.1-3 of NUREG-1800 but were not included in Table 4.1-1 of the LRA.

In its RAI response dated May 23, 2003, the applicant indicated that the following topics listed in NUREG-1800 as applicable to pressurized-water reactor (PWR) facilities were not included in Table 4.1-1 of the LRA:

- metal corrosion allowance
- inservice local metal containment corrosion allowance
- high-energy line break analysis based on cumulative usage factor
- fatigue analysis for the main steam supply lines to the auxiliary feedwater pump
- fatigue analysis of the polar crane

The applicant stated that a metal containment corrosion allowance is not applicable to Ginna because it has a concrete containment, and that high-energy line breaks were not postulated based on fatigue usage at Ginna. The staff review of the Ginna UFSAR did not identify TLAAs associated with these topics. Therefore, the staff finds the applicant's response acceptable.

The applicant indicated that no specific fatigue analysis was performed for the turbine-driven auxiliary feedwater steam supply lines; however, the American National Standards Institute (ANSI) B31.1 analysis of the these lines is addressed in LRA Subsection 4.3.2. The applicant also indicated that Ginna did not have a polar crane, and that other cranes are addressed in LRA Section 4.7.5. The staff finds the applicant's response reasonable because the applicant has identified crane load cycle limits as TLAAs, and the applicant has performed a TLAA assessment of ANSI B31.1 piping.

The applicant also indicated that metal corrosion was used in supplier calculations, but was not incorporated in the CLB. The staff requested that the applicant describe the basis for the corrosion allowance used in the vendor calculations. The applicant indicated that the corrosion allowance was based on consideration of 40 years of operation, but that no specific TLAA evaluation was performed. Instead, the applicant indicated that a one-time inspection is planned to assess the loss of material due to corrosion. The applicant indicated that this inspection would be completed prior to the period of extended operation. The staff finds that the applicant's proposed one-time inspection is an acceptable method to assess the loss of material due to corrosion. A discussion of the One-Time Inspection Program is provided in Section 3.0.3.7 of this SER.

4.1.3 Conclusions

On the basis of its review, the staff concludes that the applicant has provided an acceptable list of TLAAs, as required by 10 CFR 54.21(c)(1), and has confirmed that no 10 CFR 50.12 exemptions have been granted on the basis of a TLAA, as required by 10 CFR 54.21(c)(2).

4.2 Reactor Vessel Neutron Embrittlement

The applicant has identified three analyses affected by irradiation embrittlement that have been identified as TLAAs. These analyses are discussed in Sections 4.2.1 through 4.2.3 of the LRA and include the following:

- reactor vessel upper-shelf energy
- pressurized thermal shock
- pressure/temperature curves

Neutron embrittlement is a significant aging mechanism for all ferritic materials that have a neutron fluence of greater than 10^{17} neutrons per squared centimeters (n/cm^2) (E>1 million electron volts (MeV)). The relevant calculations used predictions of the cumulative damage to the reactor vessel (RV) from neutron embrittlement, and were originally based on the 40-year expected life of the plant. The reactor pressure vessel (RPV) contains the core fuel assemblies and is made of thick steel plates that are welded together. Neutrons from the fuel in the reactor irradiate the vessel as the reactor is operated and change the material properties of the steel. The most pronounced and significant changes occur in the material property known as fracture toughness. Fracture toughness is a measure of the resistance to crack extension in response to stresses. A reduction in this material property due to irradiation is referred to as embrittlement. The largest amount of embrittlement usually occurs at the section of the vessel's wall closest to the reactor fuel, otherwise referred to as the vessel's beltline. The rate at which the vessel's steel embrittles also depends on its chemical composition. The amounts of two elements in the steel, specifically copper and nickel, are the most important chemical elements in determining how sensitive the steel is to neutron irradiation.

4.2.1 Reactor Vessel Upper-Shelf Energy

The U.S. Nuclear Regulatory Commission (NRC) regulations that provide screening criteria for the upper-shelf energy (USE) are in 10 CFR Part 50, Appendix G. Appendix G to 10 CFR Part 50 requires that reactor vessel beltline materials have Charpy USE values in the transverse direction for the base metal and along the weld for the weld material, according to the American Society of Mechanical Engineers (ASME) Code, of no less than 75 foot-pounds (ft-lb) (102 joules (J)) initially, and must maintain Charpy USE values throughout the life of the vessel of no less than 50 ft-lb (68 J). However, in accordance with paragraph IV.A.1.a., Charpy USE values below these criteria may be acceptable if it is demonstrated, in a manner approved by the Director, Office of Nuclear Reactor Regulation, that the lower values of Charpy USE will provide margins of safety against fracture equivalent to those required by Appendix G to Section XI of the ASME Code. Regulatory Guide (RG) 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," provides an expanded discussion regarding the calculations of Charpy USE values. It also describes two methods for determining Charpy USE values for RV beltline materials, depending on whether or not a given RV beltline material is represented in the plant's Reactor Vessel Material Surveillance Program (i.e., the 10 CFR Part 50, Appendix H program). If surveillance data are not available, the Charpy USE is determined in accordance with position 1.2 in RG 1.99, Revision 2. If two or more surveillance data are available, the Charpy USE should be determined in accordance with position 2.2 in RG 1.99, Revision 2. These methods refer to Figure 2 in RG 1.99, Revision 2, which indicates that the percentage drop in Charpy USE is dependent upon the amounts of copper and the neutron fluence. Because the analyses performed in accordance with Appendix G to 10 CFR Part 50 are based on a flaw with a depth equal to one-quarter of the vessel wall thickness (1/4T), the neutron fluence used in the Charpy USE analysis is the neutron fluence at the 1/4T depth location.

4.2.1.1 Summary of Technical Information in the Application

The applicant indicated that calculations have shown that the vessel beltline Charpy USE for the limiting weld is expected to decrease to less than 50 ft-lb (68 J) based on RG 1.99, Revision 2. Consequently, a low upper-shelf fracture mechanics analysis has been performed to evaluate the weld material for ASME Levels A, B, C, and D service loadings, based on the acceptance criteria of ASME Code, Section XI, Appendix K, "Assessment of Reactor Vessels With Lower Upper Shelf Energy Charpy Impact Energy Levels." The analysis demonstrates that the limiting RV beltline weld satisfies the ASME Code requirements of Appendix K for ductile flaw extensions and tensile stability using projected low upper-shelf Charpy impact energy levels for the weld material at 52 effective full-power years (EFPYs), which corresponds to the EFPY at the end of the extended period. ASME Code, Section XI, Appendix K contains a methodology and criteria acceptable to the staff for satisfying the requirement in paragraph IV.A.1.a. to demonstrate that materials with Charpy USE values below 50 ft-lb (68 J) provide margins of safety against fracture equivalent to those required by Appendix G to Section XI of the ASME Code. Therefore, by performing an analysis in accordance with ASME Code, Section XI, Appendix K, the applicant has satisfied the requirements in paragraph IV.A.1.a of Appendix G to 10 CFR Part 50 for 52 EFPYs.

4.2.1.2 Staff Evaluation

In response to RAI 4.2.1-1, the applicant provided, in a letter dated April 11, 2003, its low upper-shelf fracture mechanics analysis of the limiting weld in the Ginna RV. The analysis is described in Framatone Report BAW-2425, Revision 1, "Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessel of R.E. Ginna for Extended Life Through 54 Effective Full Power Years," which is Enclosure 1 in the letter dated April 11, 2003. The analysis concluded that the SA-847 circumferential weld in the Ginna RPV satisfies ASME Code Section XI, Appendix K, for Levels A, B, C, and D service loadings for 54 EFPYs (i.e., 60 years of operation at 90 percent capacity factor). This analysis satisfies the requirements of 10 CFR 54.21(c)(1)(ii) for RV USE for 54 EFPYs. Because the applicant indicates that 52 EFPYs corresponds to the end of the period of extended operation, 54 EFPYs represents 2 EFPYs beyond the period of extended operation.

To confirm that the applicant's analysis satisfied the criteria in ASME Code Section XI, Appendix K, the staff performed an independent analysis using the methodologies and models specified in RG 1.161, "Evaluation of Reactor Pressure Vessels With Charpy Upper-Shelf Energy Less Than 50 ft-lb," NUREG/CR-5729, "Multivariable Modeling of Pressure Vessel and Piping J-R Data," and ASME Code Section XI, Appendix K. The NRC staff confirmed the applicant's conclusion that the Ginna RV would have margins of safety against fracture equivalent to those required by Appendix G to Section XI of the ASME Code through the period of extended operation.

4.2.2 Pressurized Thermal Shock

Section 50.61 of Title 10 of the *Code of Federal Regulations* provides the fracture toughness requirements protecting the reactor vessels of PWRs against the consequences of pressurized thermal shock (PTS). Licensees are required to perform an assessment of the RV materials' projected values of the reference temperature for PTS, RT_{PTS}, through the end of their operating license. The rule requires each licensee to calculate the end-of-life RT_{PTS} value for each material located within the beltline of the RPV. The RT_{PTS} value for each beltline material is the sum of the unirradiated reference nil ductility transition temperature (RT_{NDT}) value, a shift in the RT_{NDT} value caused by exposure to high energy neutron irradiation of the material (i.e., the DRT_{NDT} value), and an additional margin value to account for uncertainties (i.e., M value). Section 50.61 of Title 10 of the *Code of Federal Regulations* also provides screening criteria against which the calculated values are to be evaluated.

RV beltline base metal materials (forging or plate materials) and longitudinal (axial) weld materials are considered to provide adequate protection against PTS events if the calculated RT_{PTS} values are less than or equal to 270 °F. RV beltline circumferential weld materials are considered to provide adequate protection against PTS events if the calculated RT_{PTS} values are less than or equal to 300 °F. RG 1.99, Revision 2, provides an expanded discussion regarding the calculations of the shift in the RT_{NDT} value caused by exposure to high energy neutron irradiation and the margin value to account for uncertainties. In this RG, the shift in the RT_{NDT} value caused by exposure to high energy neutron irradiation is the product of a chemistry factor and a fluence factor. The fluence factor is dependent upon the neutron fluence and the chemistry factor may be determined from surveillance material or from the tables in the RG. If the RV beltline material is not represented by surveillance material, its chemistry factor and the shift in the RT_{NDT} value caused by exposure to high energy neutron irradiation may be determined using the methodology documented in position 1.1 and the tables in this RG. The chemistry factor determined from the tables in the RG depends upon the amount of copper and nickel in the beltline. If the RV beltline material is represented by surveillance material, its chemistry factor may be determined from the surveillance data using the methodology documented in position 2.1 of RG 1.99, Revision 2. Section 50.61 of Title 10 of the *Code of Federal Regulations* contains methods of determining RT_{NDT} values equivalent to RG 1.99, Revision 2.

4.2.2.1 Summary of Technical Information in the Application

The applicant indicated that it completed the projected RT_{PTS} calculation using generic data, although plant-specific data were available, because generic data proved to be more conservative. Therefore, RG 1.99, Revision 2, position 1.1 was used to calculate the RT_{PTS} for 52 EFPYs. The licensee calculations of RT_{PTS} values for the Ginna RV beltline materials will remain below the 10 CFR 50.61 PTS screening criteria through 52 EFPYs, the end of the period of extended operation.

4.2.2.2 Staff Evaluation

In the license renewal submittal, the licensee provided RT_{PTS} analyses for the materials in the Ginna RV beltline. Table 4.2-1 in the submittal provides the chemistry factor and the predicted RT_{PTS} value through 52 EFPYs for each forging and weld in the Ginna RV beltline. In addition, the applicant has projected that one weld is to be 11 °F below the PTS screening limit at the end of the period of extended operation.

To verify the predicted RT_{PTS} value through 52 EFPYs, the staff requested that the applicant describe the analysis performed to determine the neutron fluence. In response to RAI 4.2.2-1, the applicant provided its analysis to determine the neutron fluence for the pressure vessel. The analysis is described in Westinghouse Commercial Atomic Power (WCAP) report, WCAP-15885, Revision 0, “R.E. Ginna Heatup and Cooldown Limit Curves for Normal Operation,” which was enclosed in the letter dated April 11, 2003. Section 3.0 of this WCAP contains the calculational methodology and the validation of the calculated results as compared to surveillance capsule measured data.

The methodology is based on the DORT 3.1 discrete ordinates neutron transport code using the BUGLE-96 cross sections derived from the ENDF/B-VI cross section library. A three-dimensional solution was constructed based on $\varphi(r,\theta)$ and $\varphi(r,z)$ solutions. The $\varphi(r,\theta)$ solution used 170 and 67 radial and azimuthal intervals, respectively, for the representation of the 1/8 core. The $\varphi(r,z)$ solution used 153 and 90 intervals, respectively. Both meshes are considered adequate. Source distributions were obtained from cycle loading reports, which is the usual practice. In general, the methodology satisfies the guidance in RG 1.190; therefore, it is acceptable.

This section of the WCAP also compares the plant-specific dosimetry measurements to the corresponding calculations. The comparisons indicate an excellent mean value, although the uncertainties are higher than normal but well within the guidance of RG 1.190. Therefore, they are acceptable. The staff concludes that the methodology and the validation for the Ginna 32 and 54 EFPY fluence values are acceptable and may be used to determine the impact of neutron fluence on RV materials in the beltline region (the region adjacent to the reactor core).

This methodology has not been qualified for calculations above or below the beltline region. However, for regions above or below the core, the expected uncertainties would be higher than those in the beltline region, but no greater than a factor of 2. As a result of extending the license, the applicant determined that the weld between the intermediate shell and the nozzle shell would receive a neutron fluence greater than 10^{18} n/cm^2 (E>1 MeV). This weld is 10 inches above the top of the core. Because the methodology has not been qualified for determining the neutron fluence for this weld, the staff requested that the applicant perform a RT_{PTS} calculation assuming a factor of 2 increase in the neutron fluence.

This analysis is contained in Attachment 4 to a letter dated June 10, 2003. In the RT_{PTS} calculation contained in this attachment, the applicant compared the RT_{PTS} values for the intermediate shell to the nozzle weld (identified as the SA-1101 weld) to the intermediate shell to the lower shell weld (identified as the SA-847 weld). The SA-1101 and SA-847 welds are circumferentially oriented because the Ginna RPV shell segments were fabricated from forgings. The neutron fluence at the inside surface for the SA-847 weld was 5.01×10^{19} n/cm^2 and the neutron fluence for the SA-1101 weld was 0.396×10^{19} n/cm^2, which is twice the neutron fluence for the intermediate shell to the nozzle weld at 54 EFPYs. The RT_{PTS} value for the SA-1101 weld was 268.2 °F when using the RG 1.99, Revision 2, Table 1 chemistry factor (based on the amounts of copper and nickel in the weld). The RT_{PTS} value for the SA-847 weld was 270.6 °F when using surveillance data to calculate the chemistry factor, and 282.5 °F when using Table 1 in RG 1.99, Revision 2, to calculate the chemistry factor. The chemistry factors in Table 1 of RG 1.99, Revision 2, are based on the amount of copper and nickel in the weld and are the same as those specified in Table 1 of 10 CFR 50.61. Because the RT_{PTS} value for the SA-1101 weld is less than the RT_{PTS} value for the SA-847 weld, and since the RT_{PTS} value for the SA-1101 weld was calculated using a neutron fluence 2 times greater than the mean value using the applicant's neutron fluence methodology, the SA-1101 weld will not be limiting throughout the period of extended operation.

In its letter dated June 10, 2003, the applicant changed its method of determining the RT_{PTS} value for the limiting weld, SA-847, from one that was based on the chemistry factor from Table 1 in RG 1.99, Revision 2, and 10 CFR 50.61 to one that was based on the use of the Ginna surveillance data. Section 50.61 of Title 10 of the *Code of Federal Regulations* identifies two methods of determining the chemistry factor and RT_{PTS} value—one based on the amount of copper and nickel in the weld and one based on the use of surveillance data. As specified in 10 CFR 50.61(c)(2)(ii)(A), when the surveillance data are deemed credible, according to the criteria of 10 CFR 50.61(c)(2)(I), they must be used to determine the material-specific chemistry factor. The applicant chose to use surveillance data in determining the chemistry factor, but has not demonstrated that the data satisfy the credibility criteria of 10 CFR 50.61(c)(2)(I).
The chemistry factor identified in the letter dated June 10, 2003, is 161.9 °F. The chemistry factor identified for this weld in the Reactor Vessel Integrity Database (RVID) is 158.7 °F, which is based on the surveillance data. Although the difference in the chemistry factor calculated by the applicant and that in the RVID is small, the staff would like to review the surveillance data and methodology utilized by the applicant to determine the chemistry factor and to confirm that the results satisfy 10 CFR 50.61. The applicant is to provide the surveillance data, the detailed calculations for determining the chemistry factor from the surveillance data, and the analysis that demonstrates that the surveillance data meet the credibility criteria in 10 CFR 50.61. In addition, this analysis differs from that identified in UFSAR Section A3.1.2. The applicant was also requested to provide an update to this UFSAR section. This is Open Item 4.2.2-1.

In Attachment 3 to a letter dated December 9, 2003, the applicant provided the surveillance data that were contained in Section 2 of WCAP-15885. The neutron fluence for each capsule had been revised in accordance with the methodology in RG 1.190, and the surveillance weld chemistry had been revised based on additional chemical analysis performed on irradiated samples.

Paragraph (c)(2)(I) of 10 CFR 50.61 indicates that the results from the surveillance program must be integrated into the RT_{NDT} estimate if the plant-specific surveillance data is deemed credible as judged by the following criteria:

(a) The material in the surveillance capsules must be those which are controlling materials with regard to radiation embrittlement.

(b) Scatter in the plot of Charpy energy versus temperature for the irradiated and unirradiated conditions must be small enough to permit the determination of the 30 ft-lb temperature unambiguously.

(c) Where there are two or more sets of surveillance data from one reactor, the scatter of ΔRT_{NDT} values must be less than 28 °F for welds and 17 °F for base metal.

(d) The irradiation temperature of the Charpy specimens in the capsule must be within plus or minus 25 °F of the vessel wall temperature at the cladding/base metal interface.

(e) The surveillance data for the correlation monitor material in the capsule, if present, must fall within the scatter band of the data base for the material.

In Attachment 4 to a letter dated December 9, 2003, the applicant provided its evaluation of the surveillance data. The staff confirmed that the scatter for the surveillance weld metal, which is the limiting material for the Ginna reactor vessel, is within 28 °F of the best fit line through the surveillance data. The staff's best fit line was calculated in accordance with the methodology in RG 1.99, Revision 2.

The licensee's evaluation indicated that its surveillance data satisfy the criteria in paragraph (c)(2)(I) of 10 CFR 50.61 with the exception that the data from the correlation monitor material from one surveillance capsule fall 0.6 °F above the two sigma bound for the correlation monitor material. The applicant indicated that this small difference is insignificant and does not invalidate the rest of the surveillance data. The staff agrees with this conclusion. In addition, the staff agrees that the weld surveillance data should be utilized because the weld metal surveillance data represent the limiting weld in the Ginna reactor vessel.

The staff confirmed that the surveillance data were credible, in accordance with the criteria of paragraph (c)(2)(I) of 10 CFR 50.61, as discussed above, and that the RT_{PTS} value was expected to be 271 °F for the intermediate shell to the lower shell weld at the expiration of the extended license. Since the intermediate shell to lower shell weld is the limiting material in the Ginna RV, and the RT_{PTS} value for the intermediate shell to lower shell weld is less than 300 °F, the Ginna RV is adequately protected against PTS events. The proposed update to the UFSAR that is documented in the letter dated December 9, 2003, provides an adequate description of the analysis performed for pressurized thermal shock. This resolves Open Item 4.2.2-1.

4.2.3 Plant Heatup/Cooldown (Pressure/Temperature) Curves

4.2.3.1 Summary of Technical Information in the Application

The current pressure/temperature (P/T) analyses are valid beyond the current operating license period, but not to the end of the period of extended operation. The technical specifications will continue to be updated as required by Appendices G and H to 10 CFR Part 50, or as operational needs dictate. This will assure that operational limits remain valid for current and projected cumulative neutron fluence levels.

4.2.3.2 Staff Evaluation

The technical specifications will continue to be updated as required by either Appendices G or H to 10 CFR Part 50, or as operational needs dictate. This will assure that operational limits remain valid for current and projected cumulative neutron fluence levels. Because the technical specifications will continue to be updated, and since the changes must be reviewed and approved by the staff, additional analysis at this time is not required.

4.2.4 UFSAR Supplement

On the basis of the staff's evaluation described above, the summary description for the reactor coolant system (RCS) TLAA for reactor vessel USE, PTS, and P/T limits described in the UFSAR Supplement (LRA, Appendix A) provides an adequate description of this TLAA, as required by 10 CFR 54.21.

4.2.5 Conclusions

The staff has reviewed the TLAAs regarding the maintenance of acceptable reactor vessel USE for the Ginna RV materials, as well as the ability of the Ginna RV to resist failure during postulated PTS events. On the basis of this evaluation, the staff concludes that the applicant's TLAAs for Charpy USE and PTS meet the respective requirements of 10 CFR Part 50, Appendix G, and 10 CFR 50.61 for the Ginna RV beltline materials, as evaluated to the end of the extended operating period. Therefore, the TLAAs satisfy the requirements of 10 CFR 54.21(c)(1)(ii) for 60 years of operation. The staff will evaluate the end-of-extended-operating term P/T limit curves for Ginna upon submittal by the applicant. The staff's review of the end-of-extended-period-of-operation P/T limit curves, when submitted, will ensure that the operations of the RCS for Ginna will be done in a manner that ensures the integrity of the RCS during the extended periods of operation and that the curves, when submitted, will satisfy the requirements of 10 CFR 54.21(c)(1)(ii) for the period of extended operation. Because evaluation of P/T limit curves is performed when the limits are updated through the technical specification process, they need not be evaluated now; however, they will be evaluated as part of the plant's technical specifications. The technical specification process provides a process for managing P/T limits, in accordance with 10 CFR 54.21(c)(1)(iii).

4.3 <u>Metal Fatigue</u>

A metal component subjected to cyclic loading at loads less than the static design load may fail due to fatigue. Metal fatigue of components may have been evaluated based on an assumed number of transients or cycles for the current operating term. The validity of such metal fatigue analysis is reviewed for the period of extended operation.

4.3.1 Summary of Technical Information in the Application

4.3.1.1 ASME Boiler and Pressure Vessel Code, Section III, Class 1

The applicant discussed the design requirements for components of the RCS in Section 4.3.1 of the LRA. The reactor vessel, steam generators, reactor coolant pumps, and pressurizer were designed to the ASME Boiler and Pressure Vessel Code, Section III requirements for Class 1 components. The applicant stated that the reactor vessel internals (RVI) were designed in accordance with Westinghouse criteria which were later incorporated in the ASME Code. These components were subjected to design transient cycles intended to bound the thermal and pressure cycles for a 40-year operating life.

The applicant stated that, based on review of the frequency and severity of actual operating transients, it projects that the original 40-year transient set will remain bounding for 60 years of plant operation. Therefore, the applicant concluded that the fatigue analyses remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(I). The applicant indicated that, prior to the expiration of the current operating license, a Fatigue Monitoring Program will be implemented as a confirmatory program. The Fatigue Monitoring Program is discussed in Section B.3.2 of the LRA.

4.3.1.2 ANSI B31.1 Piping

The applicant discussed the evaluation of United States of America Standards (USAS) ANSI B31.1 components in Section 4.3.2 of the LRA. USAS ANSI B31.1 specifies that a stress reduction factor be applied to the allowable thermal bending stress range, if the number of full range cycles exceeds 7000. The applicant indicated that most piping systems within the scope of license renewal are only subject to occasional cyclic operation and, consequently, the analyses will remain valid during the period of extended operation. However, the applicant did indicate that the nuclear steam supply system (NSSS) sampling system could exceed the 7000 cyclic limit during the period of extended operation. The applicant committed to complete an engineering analysis of the NSSS sampling system prior to the period of extended operation (reference item 3 in Appendix A to this SER).

4.3.1.3 Reactor Vessel Underclad Cracking

The applicant indicated that WCAP-15338 is bounding for all Westinghouse plants and that the analysis has been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii). The underclad cracking TLAA is described in the UFSAR Supplement.

4.3.1.4 Accumulator Check Valves

The applicant discussed the fatigue evaluation of the accumulator check valves in Section 4.3.4 of the LRA. The applicant stated that fatigue analyses were performed on the swing check valves. The applicant indicated that the number of design transients used in the analyses bound the number of plant transient limits. Therefore, the applicant concluded that the fatigue analyses remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(I).

4.3.1.5 Reactor Vessel Nozzle-to-Vessel Weld Defect

During the first inservice inspection (ISI) of the reactor vessel in 1970, a flaw indication was discovered by ultrasonic testing (UT) in a primary nozzle-to-vessel weld at Nozzle N2B. It was determined at that time that the size of the flaw was in excess of the size permissible by the acceptance criteria in ASME Code Section XI, 1974 Edition. Consequently, the flaw was reevaluated in accordance with ASME Code Section XI, Appendix G, requirements for acceptance by evaluation and found to be acceptable. A review of the original construction radiographs confirmed the presence of slag at the same location as the flaw indication.
The same flaw indication was found by UT inspection during the second ISI in 1989.

The flaw was reexamined after the second ISI finding in 1989 using a 15°-focused beam search unit. This reexamination revealed that there are two separate flaws instead of one single flaw. The licensee asserts that the dimensions of the two separate flaws each meet the criteria for acceptance by examination in ASME Section XI, 1974 Edition with 1975 Addenda. Furthermore, the licensee stated that a fracture mechanics analysis was performed and confirmed that the indication was acceptable by evaluation, according to the requirements of ASME Section XI, Appendix G.

4.3.1.6 Pressurizer Fracture Mechanics Analysis

Preservice UT examination of the pressurizer detected a "defect-like" indication in the lower shell-to-head circumferential weld (C-3). The indication was reported as a linear reflector with the approximate dimensions of 11.5" length x 0.5" width and embedded partially in the circumferential weldment and the base metal of the pressurizer shell.

Fracture mechanics analysis was performed by Westinghouse and concluded that the "defect" would not cause failure of the pressurizer during the design life (40 years) of the component. The indication has been subject to six UT examinations since the preservice examination. The most recent UT examination (as well as two other examinations) characterized the indication as consisting of several intermittent, low-amplitude indications located in the center third of the weld thickness. The most recent examination used both automated and manual UT examinations. These indications were also evaluated and found to meet the acceptance criteria by examination in ASME Code, Section XI, 1995 Edition with 1996 Addenda. Because it has been demonstrated that the initial indication is actually a number of small, discrete indications which meet the ASME Code, Section XI acceptance criteria by examination, the fracture mechanics analysis is no longer applicable or relevant.

4.3.1.7 Environmentally Assisted Fatigue Evaluation

The applicant described the actions taken to address the issue of environmentally assisted fatigue in Section 4.3.7 of the LRA. The applicant described its evaluation of the following fatigue sensitive component locations:

- reactor vessel lower shell and lower head (lower shell at the core support pads)
- reactor vessel inlet and outlet nozzles
- pressurizer surge line (including hot leg and pressurizer nozzles)
- reactor coolant piping charging system nozzle
- reactor coolant piping safety injection nozzle
- residual heat removal system Class 1 piping

Based on its evaluation, the applicant indicated that all locations were found acceptable for the period of extended operation, with the exception of the pressurizer surge line. The applicant indicated that the pressurizer surge line will require further evaluation prior to the period of extended operation.

4.3.2 Staff Evaluation

4.3.2.1 ASME Boiler and Pressure Vessel Code, Section III, Class 1

As stated in the previous section, components of the RCS at Ginna were designed to the Class 1 requirements of the ASME Code. These requirements contain explicit criteria for the fatigue analysis of components. Consequently, the applicant identified the fatigue analyses of these components as TLAAs. The staff reviewed the applicant's evaluation of the RCS components for compliance with the provisions of 10 CFR 54.21(c)(1).

The specific design criterion for fatigue analysis of ASME Class 1 components involves calculating the cumulative usage factor (CUF). The fatigue damage in the component caused by each transient depends on the magnitude of the resulting stresses. The CUF sums the fatigue damage resulting from each transient pair. The design criterion requires that the CUF not exceed 1.0. The applicant indicated that review of the Ginna plant operating history suggests that the number of cycles and severity of the transients assumed in the design of these components envelops the expected transients during the period of extended operation. In RAI 4.3.1-1, the staff requested that the applicant provide the following information for each of the transients reviewed:

- the current number of operating cycles and a description of the method used to determine the number of the design transients from the plant operating history

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

- a comparison of the design transients with the transients monitored by the Fatigue Monitoring Program described in Section B.3.2 of the LRA, identification of any transients listed in the LRA that are not monitored by the Fatigue Monitoring Program, and an explanation of why it is not necessary to monitor these transients

The applicant's response dated May 13, 2003, indicated that the number of design transient cycles for the first 19 years of operation was documented in a report issued in 1989. The number of design transient cycles was updated in a 1995 report and subsequently updated on an annual basis. The applicant provided the cycle counts from these reports in Table 1 of the response. The design transients provided in Table 1 include the design transients listed in UFSAR Table 5.1-4. The applicant used two methods to estimate the number of cycles expected for 60 years of plant operation. The first method was a linear projection based on the first 30 years of plant operation. The second method used a weighted average based on the expectation that the more recent plant operation provided a better estimate for the future plant operation. Both methods indicated that the number of transients is not expected to exceed the number of design cycles for 60 years of plant operation.

Table 2 of the applicant's response, dated May 13, 2003, provided a detailed list of transients tracked by the Fatigue Monitoring Program. The list includes the design transients detailed in UFSAR Table 5.1-4. The applicant indicated that plant loading and unloading at 5 percent of full power per minute are not counted due to the small rate of accumulation in the first 20 years of operation. The staff agrees that the number of design cycles listed in UFSAR Table 5.1-4 for these transients is conservative based on the information presented in NUREG/CR-6260 for an older vintage Westinghouse plant.

The applicant also identified several design transients for residual heat removal, safety injection, charging, and pressurizer operations that are not listed in UFSAR Table 5.1-4. These transients affect the fatigue-sensitive components identified in NUREG/CR-6260 that the applicant evaluated for environmental fatigue. Table 2 of the applicant's response, dated May 13, 2003, indicates that the applicant will use the automated fatigue monitoring software, "FatiguePro," to estimate the number of these cycles for 60 years of plant operation, once FatiguePro has been operating for 2 years. The staff compared the transients listed in Table 2 with the transients identified in NUREG/CR-6260 that are significant contributors to the fatigue usage of the safety injection nozzle, the charging nozzle, and the residual heat removal system components. As discussed later, the applicant will perform detailed stress monitoring of critical pressurizer components using the FatiguePro software. On the basis of the review described above, the staff concludes that the applicant has provided sufficient information to assure that the thermal transients that are significant contributors to the design fatigue usage of RCS components will be monitored by the Fatigue Monitoring Program.

The Westinghouse Owners Group (WOG) issued Topical Report WCAP-14577, Revision 1-A, "License Renewal Evaluation: Aging Management for Reactor Internals," to address the aging management of the RVI. The staff review of WCAP-14577, Revision 1-A, identified a number of issues that should be addressed on a plant-specific basis. Renewal applicant action item 11 indicates that the fatigue TLAA of the RVI should be addressed on a plant-specific basis. Table 3.2.0-2 of the LRA provides the applicant's response to renewal applicant action item 11. The applicant stated that fatigue of the RVI is addressed in Section 4.3 of the LRA. Section 4.3 of the LRA indicates that the RVI were designed in accordance with Westinghouse criteria which were later incorporated into the ASME Code. In RAI 4.3.1-2, the staff requested that the applicant discuss the transients that contribute to the fatigue usage for each component listed in Table 3-3 of WCAP-14577, Revision 1-A, and detail how these transients were evaluated during the transient review described in RAI 4.3.1-1.

The applicant's response, dated May 13, 2003, indicated that Westinghouse had performed an evaluation of the structural integrity of the RVI in 1995 in support of a proposed reduction in T_{avg} following installation of the replacement steam generators. The applicant indicated that fatigue usage factors were calculated for a number of the RVI components, including the components identified in Table 3-3 of WCAP 14577, Revision 1-A. The applicant listed the transients used in the analysis of the RVI. The applicant stated that the number of transients used in the analysis bound the number expected for 60 years of plant operation. In addition, the applicant indicated that the transients will be tracked by the Fatigue Monitoring Program. The staff finds that the applicant has adequately addressed renewal applicant action item 11 in WCAP 14577, Revision 1-A, by assuring that the thermal transients that are significant contributors to the design fatigue usage of RVI components will be monitored by the Fatigue Monitoring Program.

The WOG issued Topical Report WCAP-14575-A, "Aging Management Evaluation for Class 1 Piping and Associated Pressure Boundary Components," to address aging management of the RCS piping. Renewal applicant action item 8 of the accompanying staff safety evaluation (SE) requests that a license renewal applicant perform an additional fatigue evaluation, or propose an aging management program to address components labeled I-M and I-RA in Tables 3-2 through 3-16 of WCAP-14575-A. In Table 3.2.0-1 of the LRA, the applicant indicated that an automated cycle monitoring program had been implemented at Ginna, and that this program will monitor the fatigue-sensitive locations. Table 3.2.0-1 refers to the discussion of the fatigue monitoring methodology in Section 4.0 of the LRA. The staff's review of the applicant's Fatigue Monitoring Program, as discussed above, found that the program monitors the design transients that are significant contributors to the fatigue usage of RCS components. The staff finds that the applicant has adequately addressed renewal applicant action item 8 in WCAP-14575-A by assuring that the thermal transients that are significant contributors to the design fatigue usage of RCS components will be monitored by the Fatigue Monitoring Program.

The WOG issued the generic Topical Report WCAP-14574-A, "License Renewal Evaluation: Aging Management Evaluation for Pressurizers," to address aging management of pressurizers. Renewal applicant action item 3.3.1.1-1 of the accompanying staff SE requests that a license renewal applicant demonstrate that the pressurizer subcomponent CUFs remain below 1.0 for the period of extended operation, including insurge/outsurge transients discussed in WCAP-14574-A, considering the effects of the reactor coolant environment. In Table 3.2.0-3 of the LRA, the applicant stated that FatiguePro will be used to monitor the fatigue usage of the fatigue-sensitive pressurizer locations (spray nozzle, surge nozzle, upper shell, and heater well penetration). The applicant also indicated that the effects of the reactor coolant environment would be included in the evaluation of these subcomponents. The applicant subsequently completed the evaluation of these subcomponents and found that the CUFs are not expected to exceed 1.0 during the period of extended operation. The staff's review of the applicant's evaluation of the pressurizer heater penetration and surge line nozzle is contained in Section 4.3.2.7 of this SER. The staff finds that the applicant has adequately addressed renewal applicant action item 3.3.1.1-1 in WCAP-14574-A by evaluating the fatigue-sensitive pressurizer subcomponents for insurge/outsurge transients, including the effects of the reactor coolant environment, and by assuring that the thermal transients that are significant contributors to the design fatigue usage of RCS components will be monitored by the Fatigue Monitoring Program.

On the basis of its projection of the number of design transients, the applicant has concluded that the existing fatigue analyses of the RCS components remain valid for the extended period of operation. The applicant uses its Fatigue Monitoring Program to provide assurance that the number of design cycles will not be exceeded during the period of extended operation. The staff finds that the applicant's Fatigue Monitoring Program provides an acceptable program for monitoring the fatigue usage of RCS components, in accordance with the requirements of 10 CFR 54.21(c)(1)(iii).

The applicant's UFSAR Supplement for metal fatigue of ASME Class 1 components is provided in Section A3.3.1 of the LRA. The staff finds that the UFSAR Supplement provides an adequate description of the fatigue TLAA of ASME Class 1 components to satisfy 10 CFR 54.21(d).

4.3.2.2 ANSI B31.1 Piping

ANSI B31.1 requires that a reduction factor be applied to the allowable bending stress range, if the number of full range thermal cycles exceeds 7000. The applicant stated that the number of design transient cycles was found to bound the number of transient cycles expected for 60 years of plant operation, except for the NSSS sampling system. The applicant indicated that the ANSI B31.1 limit of 7000 equivalent full range cycles may be exceeded during the period of extended operation for the NSSS sampling system, and that an engineering evaluation will be performed prior to the period of extended operation. The applicant further indicated that the effects of fatigue may be managed by an inspection program, if the results of the engineering evaluation are not acceptable. In RAI 4.3.2-1, the staff requested that the applicant provide additional clarification regarding the proposed options for addressing the NSSS sampling system. The staff also requested that the applicant describe the existing qualification of the NSSS sampling system and provide the maximum calculated thermal stress range for affected portions of the system.

The applicant's response, dated June 10, 2003, indicated that the engineering evaluation of the affected portions of the NSSS sampling had been completed. The applicant reported that the maximum calculated thermal stress range in the piping is 4,660 pounds per square inch (psi), which is less than the ANSI B31.1 stress limit specified for 100,000 or more cycles.
The applicant concluded that the NSSS sampling system is acceptable for the period of extended operation. The staff agrees with the applicant's conclusion because ANSI B31.1 does not limit the number of cycles at the calculated stress range.

The applicant's UFSAR Supplement for metal fatigue of ANSI B31.1 components is provided in Section A3.3.3 of the LRA. The applicant should update the UFSAR Supplement summary to include the TLAA evaluation of the NSSS sampling system as described above. This is Confirmatory Item 4.3-1.

By letter dated September 16, 2003, the applicant provided its response to Confirmatory Item 4.3-1. The applicant proposed to modify Section A3.3.3 of the UFSAR Supplement to indicate that analysis of the NSSS sampling system was complete and that the NSSS sampling system was found acceptable for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii). The staff finds the applicant's revised UFSAR Supplement provides an acceptable description of the NSSS sampling system TLAA to satisfy 10 CFR 54.21(d). Confirmatory Item 4.3-1 is closed.

4.3.2.3 Reactor Vessel Underclad Cracking

Underclad cracks were first discovered in October 1970 during examination of the Atucha reactor vessel. They have been reported to exist only in SA-508, Class 2 reactor vessel forgings manufactured to a coarse grain practice and clad by high heat input submerged arc processes. The underclad cracking issue was first addressed by Westinghouse Topical Report WCAP-7733 which justified the continued operation of Westinghouse plants for 32 EFPYs. Subsequently, Westinghouse submitted WCAP-15338 which extended the analysis to justify operation of Westinghouse plants for 60 years of plant operation. The staff review of WCAP-15338 is contained in a letter dated September 25, 2002, to R.A. Newton (WOG) and concluded that LRAs should include the following two action items:

- The license renewal applicant is to verify that its plant is bounded by the WCAP-15338 report. Specifically, the renewal applicant is to indicate whether the number of design cycles and transients assumed in the WCAP-15338 analysis bounds the number of cycles for 60 years of operation of its RPV.

- As required by 10 CFR 54.21(d), a UFSAR Supplement for the facility must contain a summary description of the programs and activities for managing the effects of aging, as well as the evaluation of the TLAA for the period of extended operation. Those applicants for license renewal referencing the WCAP-15338 report for the RPV components shall ensure that the evaluation of the TLAA is summarily described in the UFSAR Supplement.

The NRC SER for WCAP-15338 requires the applicant to verify that its plant is bounded by the report. In response to RAI 4.3.3-1, in a letter dated May 23, 2003, the applicant indicated that the analysis of the number of Ginna cycles and transients had been accomplished, and that they were within the assumed bounds of WCAP-15338. Because the number of Ginna cycles and transients are within the assumed bounds of WCAP-15338, the conclusions of WCAP-15338 are applicable to Ginna and the amount of flaw growth resulting from 60 years of operation will not result in the loss of integrity of the Ginna RPV. Therefore, this analysis satisfies the requirements of 10 CFR 54.21(c)(1)(ii).

On the basis of the staff's evaluation described above, the summary description for the RCS TLAA for reactor vessel underclad cracking described in the UFSAR Supplement (LRA, Appendix A) provides an adequate description of this TLAA, as required by 10 CFR 54.21(d).

4.3.2.4 Accumulator Check Valves

The applicant stated that fatigue analyses were performed on the swing check valves.
The applicant reviewed the design report and concluded that the number of design transients used in the analyses bound the number of plant transients monitored by plant procedures, and that the analysis remains valid for the period of extended operation. In addition, the applicant indicated that the design transients will be monitored by plant procedures. As discussed previously, the staff found that the Fatigue Monitoring Program monitors the design transients that are significant contributors to the fatigue usage of RCS components. On the basis of the applicant’s evaluation, as confirmed by the Fatigue Monitoring Program, the staff finds that fatigue of the accumulator check valves has been adequately evaluated for the period of extended operation, in accordance with the requirements of 10 CFR 54.21 (c)(1)(I).

The applicant’s UFSAR Supplement for metal fatigue of the accumulator check valves is provided in Section A3.3.4 of the LRA. The staff finds that the UFSAR Supplement provides an adequate description of the fatigue TLAA of the accumulator check valves to satisfy 10 CFR 54.21(d).

4.3.2.5 Reactor Vessel Nozzle-to-Vessel Weld Defect

The NRC performed a safety evaluation on the reactor vessel nozzle-to-vessel weld defect and concluded that the flaw probably results from an embedded volumetric reflector from the fabrication process that has remained unchanged since construction. However, the staff requested further evaluation, per RAI 4.3.5-1, which reads as follows—

> In Section 4.3.5 it is stated that using a 15° focused beam search unit, the indication was resolved into two separate indications which met the criteria for acceptance by examination in ASME Section XI, 1974, with Summer 1995 Addenda. However, according to the Staff Evaluation section of the referenced document, USNRC Letter Johson to Mecredy, "Ginna Flaw Indication in the Reactor Vessel Inlet Nozzle Weld—1989 Reactor Vessel Examination (TAC No. 71906)," July 7, 1989, "The staff's evaluation determined that the licensee's final dimensions of 4.94" x .48" is a realistic representation of the actual flaw size. If the flaw length were assumed constant, a reduction of .036" in the depth dimension (.480"–.44") would result in a flaw indication that meets the ASME Section XI acceptance standard." Consequently, according to the staff SER, the dimensions of the flaw are not within ASME Section XI acceptance standards. Therefore a fatigue analysis for the extended period of operation for this flaw is a TLAA and its results must be provided in accordance with 10 CFR 54.21(c) and must be described in the UFSAR supplement.

In a letter dated June 10, 2003, the applicant provided a clarification to RAI 4.3.5-1. In this letter, the applicant provided a fracture mechanics analysis for the flaw based on the design transients for 40 years of operation and compared the number of design transients used in the fatigue crack growth analysis to that projected for the period of extended operation. The analysis is described in a letter dated April 26, 1989, from Structural Integrity Associates. The analysis considered the impact of neutron irradiation and fatigue crack growth. The flaw indication is 57 inches from the top of the core. At this distance, the impact of neutron irradiation was determined to be insignificant. Because the flaw is located 57 inches from the top of the core, and because there is significant attenuation of neutron fluence above the core, the staff agrees with the conclusion that the impact of neutron irradiation is insignificant. The staff's July 7, 1989, safety evaluation indicates that the 1989 inspection results and fracture mechanics analysis demonstrates that the structural integrity of the RPV will be maintained during the period of extended operation with this flaw indication in the vessel. To demonstrate that the fatigue crack growth for 40 years of operation is applicable for the period of extended operation, the applicant compared the number of design transients used in the fatigue crack growth analysis to that projected for the period of extended operation. The applicant indicated that the number of design transients used in the fatigue crack growth analysis is bounding for the period of extended operation. Therefore, the analysis satisfies the requirements of 10 CFR 54.21(c)(1)(ii).

In a letter dated July 31, 2003, and supplemented in a letter dated August 1, 2003, the applicant provided a UFSAR Supplement for this TLAA. The UFSAR Supplement provides an adequate description of this TLAA, as required by 10 CFR 54.21(d).

4.3.2.6 Pressurizer Fracture Mechanics Analysis

The most recent UT examination showed that the "defect" in weld C-3 was not just a single defect, but rather a number of small discrete indications which meet ASME Code, Section XI criteria. Therefore, the staff has concluded that fracture mechanics analysis is no longer required. Because the fracture mechanics analysis is no longer required, the analysis does not meet the criteria for a TLAA and no additional analysis is required.

On the basis of the staff's evaluation described above, the summary description for this TLAA is not required.

4.3.2.7 Environmentally Assisted Fatigue Evaluation

The applicant indicated that the Fatigue Monitoring Program will be implemented as a confirmatory program prior to the period of extended operation to assure that design cycle limits are not exceeded. The applicant's Fatigue Monitoring Program tracks transients and cycles of RCS components that have explicit design transient cycles to assure that these components stay within their design basis. Generic Safety Issue (GSI)-166, "Adequacy of the Fatigue Life of Metal Components," raised concerns regarding the conservatism of the fatigue curves used in the design of the RCS components. Although GSI-166 was resolved for the current 40-year design life of operating components, the staff identified GSI-190, "Fatigue Evaluation of Metal Components for 60-Year Plant Life," to address license renewal. The NRC closed GSI-190 in December, 1999, and concluded the following:

> The results of the probabilistic analyses, along with the sensitivity studies performed, the iterations with industry (NEI and EPRI), and the different approaches available to the licensees to manage the effects of aging, lead to the conclusion that no generic regulatory action is required, and that GSI-190 is closed. This conclusion is based primarily on the negligible calculated increases in core damage frequency in going from 40 to 60 year lives. However, the calculations supporting resolution of this issue, which included consideration of environmental effects, and the nature of age-related degradation indicate the potential for an increase in the frequency of pipe breaks as plants continue to operate. Thus, the staff concludes that, consistent with existing requirements in 10 CFR 54.21, licensees should address the effects of coolant environment on component fatigue life as aging management programs are formulated in support of license renewal.

The applicant evaluated the component locations listed in NUREG/CR-6260 that are applicable to an older vintage Westinghouse plant for the effects of the environment on the fatigue life of the components. The applicant also indicated that the later environmental fatigue correlations contained in NUREG/CR-6583, "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels," and NUREG/CR-5704, "Effects of LWR Coolant Environments on Fatigue on Fatigue Design Curves of Austenitic Stainless Steels," were considered in the evaluation. The applicant applied environmental correction factors to the calculated fatigue usage factor at those component locations with specific fatigue calculations. The applicant stated that USAS B31.1 was the design code for three of the component locations and, consequently, detailed fatigue calculations were not available for these locations. The applicant indicated that the component analysis results reported in NUREG/CR-6260 were used to develop Ginna-specific environmental fatigue calculations. The applicant stated that all locations were found acceptable for the period of extended operation, with the exception of the pressurizer surge line. In RAI 4.3.7-1, the staff requested the following for each of the six component locations listed in NUREG/CR-6260:

- For those locations with existing fatigue analyses, provide the results of the fatigue usage factor calculation, including the calculated environmental multiplier (F_{en}). Show how F_{en} was calculated.

- For the USAS B31.1 locations discussed in Section 4.3.7.3 of the LRA, describe the fatigue usage factor calculation and provide the calculated fatigue usage factor. Include a detailed comparison of the Ginna Station components with the components listed in NUREG/CR-6260 and discuss the significance of the differences. This comparison should also include any differences in the thermal sleeve designs. In addition, provide a comparison of the design transients used in the analysis of the NUREG/CR-6260 components with the anticipated transients for the Ginna Station components.

The applicant's response, dated June 10, 2003, indicated that a plant-specific fatigue analysis was performed for all six component locations. The analyses concluded that acceptable fatigue usage existed at all six locations.

The design fatigue usage factors for the Ginna reactor vessel are provided in Table 5.3-8 of the UFSAR. The applicant multiplied the design usage factors for the RPV lower shell and the RPV inlet/outlet nozzles by the maximum environmental factor for low-alloy steel components. The resulting CUFs were below 1.0. The staff notes that the environmental multipliers, as a function of temperature, shown in the applicant's response are incorrect. The environmental factor should be a constant value for low oxygen environments. However, because the applicant used the highest calculated environmental factor, the applicant's evaluation of these locations is conservative. The staff finds the applicant's evaluation of the effect of the environment on the RPV shell and the RPV inlet/outlet nozzles acceptable.

The staff notes that the highest reported CUF in Table 5.3-8 of the UFSAR for the RV nozzles is at the safety injection nozzle. This location was not identified in NUREG/CR-6260 as a high fatigue usage location for an older vintage Westinghouse PWR. The facility evaluated in NUREG/CR-6260 was a three loop Westinghouse PWR that did not have a safety injection nozzle located on the reactor vessel. The staff requested that the applicant provide additional discussion regarding this nozzle. In its response, dated July 16, 2003, the applicant indicated that the design usage factor for the nozzle is much less than the usage factor reported in Table 5.3-8 of the UFSAR. The applicant provided additional information regarding the safety injection nozzle in a letter dated August 8, 2003. The applicant compared the Ginna nozzle to a similar nozzle at the Point Beach facility. Point Beach is a two loop Westinghouse PWR designed to standard Westinghouse transients. The Point Beach design usage factor is also much lower than the value reported in Table 5.3-8 of the UFSAR. The applicant multiplied the Point Beach design usage factor by the maximum environmental factor. The resulting usage factor was less than 1.0. On the basis of the applicant's comparison of the Ginna safety injection nozzle to a similar nozzle at the Point Beach facility, the staff finds that the applicant has performed an acceptable evaluation of the environmental effects for this nozzle. The applicant should correct the design usage factor for the safety injection nozzle provided in UFSAR Table 5.3-8.

The applicant calculated the design usage factor for the safety injection nozzle and the residual heat removal line tee connection. The applicant multiplied these usage factors by the maximum environmental factor for stainless steel components. The resulting CUFs were below 1.0. This is consistent with results presented in NUREG/CR-6260 for the safety injection nozzle and the residual heat removal line tee connection. On the basis of comparison between the applicant's results and the results presented in NUREG/CR-6260, the staff finds the applicant's evaluation of these locations acceptable.

The applicant used actual plant data for the loss of letdown flow transient to calculate the fatigue usage for the charging nozzle. The applicant indicated that the loss of letdown flow transient is the most significant contributor to the fatigue usage at this nozzle. Loss of letdown transients was also identified in NUREG/CR-6260 as the most significant contributor to fatigue usage of the charging nozzle. The use of actual transient data resulted in a relatively low CUF for the charging nozzle. The applicant provided further discussion of fatigue usage of the charging nozzle in a supplemental response dated July 16, 2003. The applicant indicated that the fatigue usage for the charging nozzle is based on plant-specific geometry and transients, and that the calculated Ginna usage factor is comparable to the usage factor shown in NUREG/CR-6260. The staff agrees with the applicant that the calculated Ginna charging nozzle usage factor is reasonable in comparison to the usage factor reported in NUREG/CR-6260. The staff also notes that the resulting Ginna charging nozzle CUF is less than 1.0. Therefore, the staff finds the applicant's evaluation of the charging nozzle acceptable.

The remaining locations evaluated by the applicant were the pressurizer lower head and surge line. As discussed in Section 4.3.2.1 of this SER, the applicant stated that detailed fatigue monitoring would be used to monitor the fatigue-sensitive pressurizer locations, including the environmental effects. The applicant's response, dated June 10, 2003, provided additional details regarding its evaluation of the pressurizer heater penetration weld, surge line nozzle, and pressurizer lower head components. The applicant developed finite element models for the pressurizer surge leg nozzle and the RCS hot leg nozzle for use with the Fatigue Monitoring Program. The applicant uses FatiguePro to compute the incremental fatigue usage at these component locations for known plant transients using measured plant data. The applicant indicated that the fatigue usage at these component locations is primarily due to the temperature differentials that occur during plant heatup and cooldown cycles. The applicant used historical data from actual plant heatup and cooldown events to obtain the temperature differentials for early plant operations. The applicant performed an analysis using FatiguePro to estimate the fatigue usage resulting from these temperature differentials.

The applicant's evaluation of the surge leg nozzle and the RCS hot leg nozzle indicates that the CUF is not expected to exceed 1.0 during the period of extended operation. In addition, the applicant indicated that an evaluation of pressurizer heater penetration found that the CUF is not expected to exceed 1.0 during the period of extended operation. The applicant's evaluation is based on the number of heatup and cooldown cycles specified in UFSAR Table 5.1-4. The staff finds the applicant's evaluation of these component locations reasonable. The applicant's Fatigue Monitoring Program will provide assurance that the number of design cycles will not be exceeded during the period of extended operation.

The applicant evaluated the effects of the reactor water environment on the fatigue-sensitive locations at Ginna and concluded that the resulting fatigue usage will be acceptable for the period of extended operation. The applicant uses its Fatigue Monitoring Program to provide assurance that the number of design cycles used in the evaluations will not be exceeded in the period of extended operation. The staff finds that the applicant's Fatigue Monitoring Program provides an acceptable program for monitoring the environmental fatigue usage of fatigue-sensitive locations in accordance with the requirements of 10 CFR 54.21(c)(1)(iii).

The applicant's UFSAR Supplement for metal fatigue of environmentally assisted fatigue is provided in Section A3.3.5 of the LRA. The applicant provided an additional discussion of the pressurizer surge line in Section A3.3.6 of the LRA. The applicant should update the UFSAR Supplement summary to include a description of the completed environmental fatigue evaluation of the pressurizer surge line, as described above. This is Confirmatory Item 4.3-2.

By letter dated September 16, 2003, the applicant provided its response to Confirmatory Item 4.3-2. The applicant proposed to modify Section A3.3.6 of the UFSAR Supplement to provide a discussion of its completed analysis of the pressurizer lower head and surge line. The applicant indicated that fatigue-sensitive locations will be monitored by the Fatigue Monitoring Program. The staff finds the applicant's revised UFSAR Supplement provides an acceptable description of its evaluation of environmental fatigue effects to satisfy 10 CFR 54.21(d). Confirmatory Item 4.3-2 is closed.

4.3.3 Conclusions

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1), that, for the metal fatigue TLAA, the effects of aging on the intended functions will be adequately managed during the period of extended operation. Therefore, the staff has reasonable assurance that the safety margins established and maintained during the current operating term will be maintained during the period of extended operation, as required by 10 CFR 54.21(c)(1).

4.4 <u>Environmental Qualification of Electrical Equipment</u>

The Ginna 10 CFR 50.49 Environmental Qualification Program has been identified as a TLAA for the purpose of license renewal. The applicant is considering for review as a TLAA only the environmental qualification (EQ) packages which indicate a qualified life of greater than 40 years. Equipment qualification packages that indicate a qualified life of less than 40 years are not considered TLAAs and will not be considered as such in the context of license renewal.
The applicant stated that many of the EQ analyses may have been adequate under existing conditions and conform to 10 CFR 54.21(c)(1)(I); however, the applicant chose to be conservative and performed a confirmatory evaluation to verify that the assumptions in the existing analysis were adequate for the period of extended operation.

4.4.1 Summary of Technical Information in the Application

In LRA Section 4.4, the applicant described its TLAA evaluation for EQ components.
The applicant stated that many of the EQ analyses may have been adequate under existing conditions and conform to 10 CFR 54.21(c)(1)(I). However, the applicant was conservative and performed a confirmatory evaluation to verify that the assumptions in the existing analysis were adequate for the period of extended operation. The TLAAs for EQ components were evaluated in accordance with 10 CFR 54.21(c)(1).

On October 15, 2002, representatives of the applicant met with the staff to review a sample of the EQ calculations. The following calculations were reviewed:

Item	Licensee Item No.	
(1)	4.4.1.4	Valcor Solenoid Operated Valve Models V526-6042-3 and V526-6042-17
(2)	4.4.5.10	General PVC Insulated and Jacketed Control Cable
(3)	4.4.5.14	Conax Core Exit Thermocouple Connector/Cable Assemblies
(4)	4.4.5.3	Conax Electric Conductor Seal Assembly
(5)	4.4.3.2	Westinghouse/WX32714 Electrical Penetration Assembly
(6)	4.4.5.1	Kerite 600V HTK Insulated and FR Jacketed Power Cable
(7)	4.4.2.1	Westinghouse Containment Recirculation Fan Motor
(8)	4.4.6.5	AMP Nuclear PIDG Window Butt Splices and Terminals
(9)	4.4.7.2	Conax RTD Model 7DB9-10000
(10)	4.4.4.4	Raychem WCSF-N Nuclear Low Voltage Tubing
(11)	4.4.5.16	Brand-Rex XLPE Insulated and CSPE Jacketed Cable
(12)	4.4.2.2	Limitorque Actuators Outside Containment
(13)	4.4.8	Victoreen High Range Radiation Monitor
(14)	4.4.1.2	Valcor Solenoid Operated Valve Model V526-5440-2
(15)	4.4.2.4	Limitorque Motor Operated Valve Model SMB-00-15 with Reliance Motor

The sample calculations represent certain equipment types including solenoid operated valves, electric motors, electrical penetration assemblies, heat shrink tubing, wire and cable, electrical connectors, resistance temperature detectors, and high range radiation monitors.

The applicant discussed items mostly falling under 10 CFR 54.21(c)(1)(ii), but also provided examples of the use of 10 CFR 54.21(c)(1)(I) and 10 CFR 54.21(c)(1)(iii). The Arrhenius methodology was used to perform the thermal aging evaluation, and the temperature data used in the evaluation were based on plant design temperature or on actual plant temperature data.

The applicant stated that due to the date of installation of certain equipment subsequent to 1989, reanalysis was not required for license renewal purposes for equipment whose previous thermal and radiation analyses support a qualified life of 40 years.

The applicant also confirmed that there are no plans to extend the qualification of certain equipment which is expected to be replaced at the end of its qualified life. For the equipment that is not expected to be replaced at the end of its qualified life, the applicant has performed reanalysis in accordance with NUREG-1800, Table 4.4-1. All equipment so analyzed has been qualified through the period of extended operation.

4.4.2 Staff Evaluation

In accordance with 10 CFR 54.29, the staff reviewed the Ginna LRA, Section 4.4, “Environmental Qualification of Electric Equipment,” and Appendix B, Section B 3.1, “Environmental Qualification Program,” to determine if the applicant had demonstrated compliance with the requirements set forth in 10 CFR 54.21(c)(1) for EQ components. The staff also reviewed the following EQ guidance documents (as applicable)—RG-1.97, “Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident,” Revision 3; Information and Enforcement Bulletin (IEB) 79-01B, “Environmental Qualification of Class 1E Equipment”; NUREG-0588 (Category II), “Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment”; and the NRC guidance for addressing GSI-168 for license renewal, as contained in a letter to NEI dated June 2, 1998.

In LRA Appendix A, UFSAR Supplement, Section A3.4, “Environmental Qualification of Electric Equipment,” the applicant stated that the EQ equipment is identified in the Ginna Station EQ Master List. Only the equipment qualification packages which indicate a qualified life of greater than 40 years were reviewed by the applicant as a TLAA. Equipment qualification packages that indicate a qualified life of less than 40 years are not TLAAs, as defined in 10 CFR 54.3, and therefore need not be discussed in the context of license renewal. The EQ reanalysis has been performed to verify extension of environmental qualification to 60 years. The re-analysis attributes and methodology descriptions used for EQ TLAAs include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions. These attributes are discussed in the following paragraphs.

Analytical Methods. The applicant use the same analytical models as those in previous evaluations. The Arrhenius methodology used by the applicant is the thermal model accepted by the staff for performing its current thermal aging analyses. The analytical method used by the applicant for radiation aging analysis demonstrates qualification for the total integrated dose, that is, the normal radiation dose for the projected installed life plus the accident radiation dose. The staff accepted this approach for the current operating term of 40 years.

For license renewal, the applicant stated that it will establish the 60-year normal radiation dose by multiplying the 40-year normal radiation dose by 1.5 (60 years/40 years = 1.5). The result is added to the accident radiation dose to obtain the total integrated dose for each applicable component. For cyclical aging, a similar approach will be used. The staff determined that the applicant’s approach for thermal, radiation, and cyclical aging is consistent with its CLB, and that it can be effective in determining the added aging for the period of extended operation.

Data Collection and Reduction Methods. The applicant stated that reduction of excess conservatism in component service conditions (e.g., temperature, radiation, cycles) that was used in its prior aging analyses is the primary method that will be used for reevaluating the qualified life for the period of extended operation. The temperature used in an aging evaluation should be conservative and should be based on plant design temperature or actual plant temperature data. When used, temperature data can be obtained in several ways, including monitors, measurements made by plant operators during rounds, and temperature sensors on large motors. Plant temperature data may be used in an aging evaluation in different ways, such as (1) directly in the evaluation, or (2) to demonstrate conservatism when using plant design temperature for an evaluation.

Changes to material activation energy values as part of a reevaluation are to be justified on a component/materials-specific basis. Similar methods of reducing excess conservatism in the component service conditions used in prior aging evaluations can be used for radiation and cyclical aging.

The staff reviewed the applicant's data collection approach and found it to be conservative and bounding. The elimination of excessive conservatism is consistent with 10 CFR 50.49. In addition, the reduction method described by the applicant is also acceptable to the staff. The staff also agrees that changes to material activation energy values need to be determined on a component/material-specific basis.

Underlying Assumptions. The applicant states that EQ component aging evaluations contain sufficient conservatism to account for most environmental changes occurring due to plant modifications and events. When unexpected adverse conditions are identified during operational or maintenance activities that affect the normal operating environment of a qualified component, the affected EQ component is evaluated and appropriate corrective actions are taken which may include changes to the qualification bases and conclusions.

Acceptance Criteria and Corrective Action. The applicant stated that under its Environmental Qualification Program, the reevaluation of an aging analysis could extend the qualified life of a component. If the qualified life of a component cannot be extended by reevaluation, the component must be refurbished, replaced, or requalified prior to exceeding the period for which the current qualification remains valid, in conformance with 10 CFR 50.49. Reevaluations must be performed in a timely manner, that is, the reevaluation must be completed with sufficient time available to refurbish, replace, or requalify the component prior to exceeding its qualified life, if the reevaluation is unsuccessful.

4.4.3 Conclusions

On the basis of the review described above, the staff has determined that there is reasonable assurance that the applicant has adequately identified the TLAA for EQ components, as defined in 10 CFR 54.3. In addition, the staff finds that in combination with the staff's review of the Environmental Qualification Program, as documented in Appendix B to the LRA, the applicant has demonstrated that the effects of aging on the intended functions of these components will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(c)(1).

The staff has also reviewed the revised UFSAR Supplement for this TLAA and concludes that it provides an adequate summary description of the TLAA to satisfy 10 CFR 54.21(d).

4.5 Concrete Containment Tendon Prestress

The prestressing tendons in prestressed concrete containments lose their prestressing forces with time due to creep and shrinkage of concrete and relaxation of the prestressing steel. During the design phase, engineers estimate these losses to arrive at the end of the operating life, normally 40 years. The operating experiences with the trend of prestressing forces indicate that the prestressing tendons lose their prestressing forces at a rate higher than predicted due to sustained high temperature. Thus, it is necessary to perform TLAAs for the period of extended operation. The adequacy of the prestressing forces in prestressed concrete containments is reviewed for the period of extended operation.

4.5.1 Summary of Technical Information in the Application

The applicant briefly described the basic characteristics of the containment in Section 4.5 of the LRA. The applicant stated that the prestressing force of containment tendons may decrease over time due to creep, shrinkage, and elastic shortening of the concrete and stress relaxation of the prestressing tendon wires. The applicant indicated that prestressing tendon integrity is monitored and confirmed by the ASME Section XI, Subsection IWE/IWL Inservice Inspection Program.

The applicant provided the following description of its containment tendon prestress TLAA:

> An analysis was performed to evaluate the trend in the loss of prestress for each of the 160 tendons at Ginna Station. A review of the historical lift-off force measurements for the tendons was conducted. It was appropriate to review the results as two separate groups, i.e., the 23 tendons which were retensioned in 1969, and the 137 tendons which were retensioned in 1980. Of the 23 tendons that were retensioned in 1969, eleven have been tested during the surveillances since 1980. Of the 137 tendons that were retensioned in 1980, forty-seven have been tested during the subsequent surveillances. The number of tendons sampled during the surveillance tests exceeds the requirements of Regulatory Guide 1.35.
>
> Using the guidance in RG 1.35.1, tolerance bands were calculated and the lift-off forces measured during surveillance tests were expressed in terms of margins. It was concluded that the group of 23 tendons originally retensioned in 1969 should be retensioned as documented in the Evaluation of Loss of Prestress in Containment Tendons TLAA. These tendons have exhibited loss of prestress as determined during previous surveillance tests. Retensioning should preclude further loss of prestress.

Based on the analysis performed, the applicant concluded that retensioning the group of 23 tendons in 2005 will provide additional assurance that the minimum design tendon prestress force will be maintained through the period of extended operation.

4.5.2 Staff Evaluation

In addition to the review of Section 4.5 of the LRA, the staff reviewed the relevant information in Sections 2.4.1, 3.6, B2.1.3, B3.3, and Section 4.7.4 of the LRA. In the earlier years (1979–1980), the applicant had experienced lower prestressing forces than the minimum required value (MRV) estimated at 40 years. In order to understand the present state of the prestressing forces in the Ginna containment, the staff requested that the applicant provide the following additional information in RAI 4.5-1:

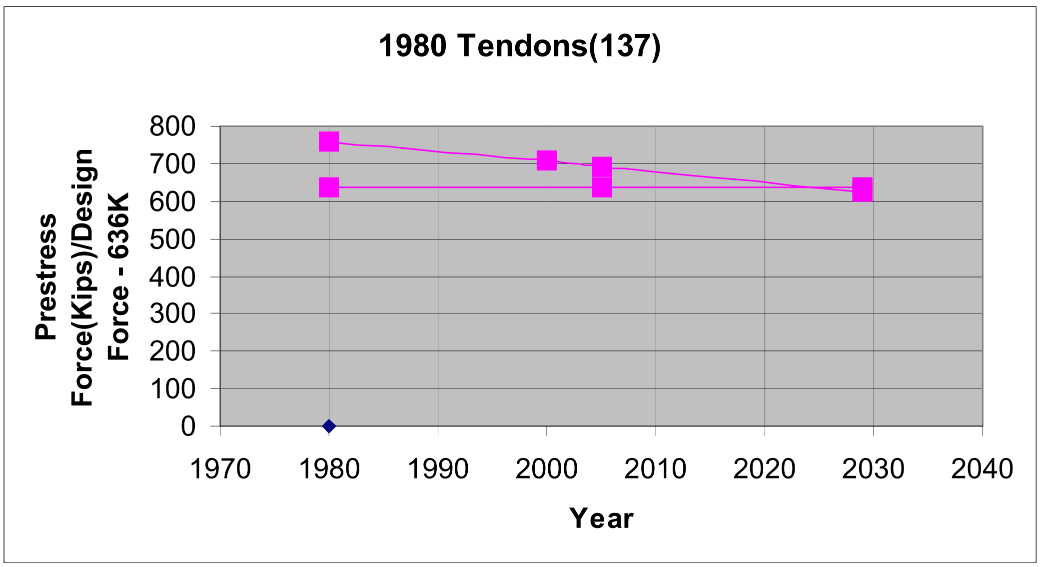
1. For the 137 tendons which were retensioned in 1980, the applicant was requested to provide the predicted lower limit line, MRV expected in 2005 and at 60 years (if not retensioned in 2005), a trend line for this group of tendons, and prestressing force values as points above and below the trend line measured during prior inspections.

2. The applicant was requested to provide the same information for the remaining 23 tendons for the inspections performed after the 1969 retensioning.

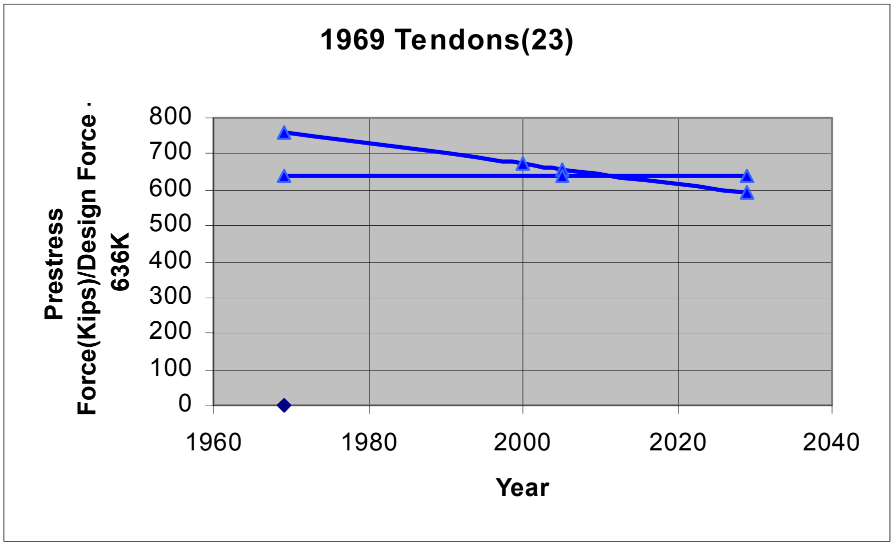
3. The operating experience element of Section B3.3 of the LRA indicates that 23 tendons out of 160 tendons were retensioned 1000 hours after initial prestressing. It was not clear if the 23 tendons retensioned after initial prestressing were parts of the randomly selected tendons in the subsequent surveillance of tendons performed as per RG 1.35 or IWL-2520.
The applicant was requested to provide information regarding the trending of prestressing forces in these 23 tendons.

In response, the applicant provided the following information:

a) Based on the available test information for this set of 137 tendons that were retensioned in 1980, the below graph shows the trend line from 1980 projected through 2005, and out to 2029. The graph also includes a constant line at 636 kips, which is the minimum design prestress force.



b) Based on the available test information for this set of 23 tendons that were retensioned in 1969, the below graph shows the trend line from 1969 projected through 2005, and out to 2029. The graph also includes a constant line at 636 kips, which is the minimum design prestress force.



c) Following the initial installation and retensioning of those 23 tendons in 1969, they were then included into the total population of tendons for the structure (160), which were subsequently randomly sampled and tested per Regulatory Guide 1.35 through the year 2000. The next scheduled tendon surveillance will be performed in the year 2005 and will be tested per the requirements of IWL-2520.

Since their retensioning in 1969, there have been 22 lift off tests performed on that population of 23 tendons.

The staff notes that in constructing the trend lines, it appears that the analyst has averaged the prestressing forces measured during each inspection. In Information Notice 99-10, the staff discouraged the averaging method. The regression analysis is more representative when each measured value is independently considered and the individual measured values are plotted on both sides of the trend line. The applicant was requested to show the individual measured values obtained during each inspection.

In the applicant's response dated July 16, 2003, the applicant provided the trend line based on the regression analysis of the measured tendon forces for the inspections performed after 1980 retensioning. On the basis of its review, the staff finds the process used in the trending analysis acceptable because it takes into account the contribution of all measured tendon forces in the regression analysis to arrive at the trend line. The staff considers the issue relative to RAI 4.5-1 to be resolved.

The applicant provided a qualitative description regarding the prestressing forces in the Ginna containment in Section A4.1 of the LRA (UFSAR Supplement). The staff believes that the applicant should, at a minimum, provide target prestressing forces that will be maintained at

40 years and 60 years. In RAI 4.5-2, the staff requested that the applicant supplement the present description in A4.1 with the basic quantitative description.

The applicant provided the following response to the staff request:

> The required minimum design prestress force for the containment structure of Ginna Station is 636 Kips. Based on data compiled for all tendons since 1969, the graphs presented in response to RAI 4.5.1 a) and 4.5.1 b) above, show the projected values for the 1969 and 1980 populations of tendons out to years 2005 and 2029. The prestress values for those two groups of tendons will provide a 4% and 8% margin above the minimum design force in 2005, and would fall below the minimum force if projected out to 2029. The tendons in the 1969 population will be retensioned in the 2005 surveillance and those in the 1980 population will be done in subsequent surveillances.

On the basis of the description provided in LRA Section A4.1, as supplemented by the above response, the staff considers the actions the applicant committed to in Section A4.1 of the LRA adequate to ensure the adequacy of prestressing forces for the containment structure during the period of extended operation.

4.5.3 Conclusions

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that for the concrete containment tendon prestress TLAA, the effects of aging on the intended functions will be adequately managed during the period of extended operation. The staff also concludes that the UFSAR Supplement contains an appropriate summary description of the concrete containment tendon prestress TLAA evaluation for the period of extended operation, as reflected in the license condition, to satisfy 10 CFR 54.21(d). Therefore, the staff concludes that the safety margins established and maintained during the current operating term will be maintained during the period of extended operation, as required by 10 CFR 54.21(c)(1).

4.6 Containment Liner Plate and Penetration Fatigue

The interior surface of the concrete containment structure is lined with welded thin metallic plates to provide an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment, as required by 10 CFR Part 50. At all penetrations, the liner plate is thickened to reduce stress concentrations.

Fatigue of the liner plates may be considered in the design based on an assumed number of loading cycles for the current operating term. The cyclic loads include reactor building interior temperature variation during the heatup and cooldown of the reactor coolant system, a loss-of-coolant accident, annual outdoor temperature variations, thermal loads due to high-energy containment penetration piping lines (such as steam and feedwater lines), seismic loads, and pressurization due to periodic Type A integrated leak rate tests.

4.6.1 Summary of Technical Information in the Application

The applicant stated that the containment liner, liner penetrations, and liner steel components of the Ginna Station containment structure comply with the ASME Code Section III—1965 for pressure boundary and the American Institute of Steel Construction (AISC) Code for structural steel. The containment liner and penetrations were designed as Class B vessels. The Winter 1965 Addenda of ASME Section III, Subsection B, N-1314(a) requires that the containment vessel satisfy the provisions of Subsection A, N-415.1, "Vessels Not Requiring Analysis for Cyclic Operation," in order for Subsection B rules to be applicable.

The applicant stated that a fatigue analysis of the containment penetrations at Ginna was not required, in accordance with the ASME Code, Section III—1965, N-415.1, provided the specified operation and service loading of the vessel or component meets the six conditions addressed in the following types of mechanical and thermal loads:

- atmospheric to operating pressure cycles
- normal service pressure fluctuations
- temperature difference—startup and shutdown
- temperature difference—normal service
- temperature difference—dissimilar materials
- mechanical loads

The pressure boundary components analyzed include the liner adjacent to the penetration, the penetration sleeve, and the annular plate connecting the pressure piping to the sleeve.
The applicant stated that an analysis was performed which verified that each of these six conditions was satisfied for the period of extended operation, and therefore demonstrated that liner and penetrations comply with the ASME Code Section III—1965 rules for fatigue through the period of extended operation. The applicant concluded that the fatigue analyses have been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

4.6.2 Staff Evaluation

In RAI 4.6-1, the staff requested that the applicant provide a list of the design transients and corresponding cycles that were specified in the design of the containment liner penetrations. In response, the applicant indicated that the design cycles for the containment liner penetrations were based on the design cycles listed in UFSAR Table 5.4-1. These design transients are discussed in the applicant's response to RAI 4.3.1-1.

The applicant indicated, in response to RAI 4.3.1-1, that the projected cycles for all transients over a 60-year period are significantly less than the total cycles given in UFSAR Table 5.1-4 over a 40-year period. However, for conservatism, the total number of design cycles from Table 5.1-4, excluding startup and shutdown, was used for the 60-year period. The applicant's response to RAI 4.3.1-1 also indicated that, based on operating experience, the total number of heatup/cooldown pressure cycles over a 60-year period is projected to be less than 120.

The applicant used 120 heatup/cooldown cycles for the evaluation instead of the 200 cycles specified in UFSAR Table 5.1-4.

The applicant summarized the six conditions and the corresponding design cycles as follows:

(1)	atmospheric to operating pressure cycles	120
(2)	normal service pressure fluctuations	17,145
(3)	temperature difference—startup and shutdown	120
(4)	temperature difference—normal service	17,145
(5)	temperature difference—dissimilar materials	1,000,000
(6)	mechanical loads	10

The staff finds these transients and their cycles acceptable because they were shown to conform with cyclic transients prescribed in Table 5.1-4 of the UFSAR and because they are consistent with cycles provided in response to RAI 4.3.1-1.

In RAI 4.6-2, the staff requested that the applicant demonstrate that, for the penetration sleeve and annular plate connecting pressure piping to the sleeve, the six conditions stated in ASME Section III, Subsection A, N-415.1, 1965, will be satisfied for the period of extended operation.

In response, the applicant stated that the pressure boundary components evaluated in the calculation included the liner adjacent to the penetration, the penetration sleeve, and the annular plate. The liner and all penetration sleeves are made of carbon steel. Most of the annular plates are also carbon steel, and the rest are made of stainless steel. Because the allowable alternating stress intensity, Sa, for stainless steel at any specific number of cycles is always greater than that allowed for carbon steel, as shown in ASME Code Figures N-415(A) and N-415(B), the design fatigue curve for carbon steel was used in all calculations. The following paragraphs provide the applicant's response to RAI 4.6-2, and the staff's evaluation, concerning the six conditions in ASME Section III, Subsection A, N-415.1, 1965:

- Condition 1, "Atmospheric to Operating Pressure Cycles," requires that the projected number of heatup/cooldown pressure cycles be less than the allowable cycles corresponding on the material fatigue curve to an alternating stress value Sa equal to 3 Sm, where Sm is the design stress intensity for the material at temperature. The pressure boundary components evaluated included the liner adjacent to the penetration, the penetration sleeve, and the annular plate connecting the pressure piping to the sleeve. For these components, the applicant determined the allowable cycles from the applicable design fatigue curve for carbon steel. On this basis, the applicant showed that Condition 1 was met because the projected number of heatup/cooldown cycles (120), was below 1500 cycles, the allowable number of cycles corresponding to 3 Sm.

- Condition 2, "Normal Service Pressure Fluctuations," requires that the full range of the pressure fluctuations that occur during normal operation not exceed an allowable full range pressure fluctuation equal to the quantity design pressure multiplied by Sa/3 Sm, where Sa is determined from the applicable design fatigue curve for the total specified number of significant pressure fluctuations at a given temperature. Based on the total number of significant pressure fluctuations of 17,145 and a design pressure of 60 psi, the applicant determined the allowable full range pressure fluctuation to be 26 psi. The pressure fluctuations in the containment during normal operation are ordinarily atmospheric fluctuations and are therefore negligible compared to the allowable full range pressure fluctuation. The applicant demonstrated that Condition 2 is satisfied.

- Condition 3, “Temperature Difference—Startup and Shutdown,” requires that the temperature difference in degrees F between any two adjacent points of the component during normal operation, and during startup and shutdown, not exceed an allowable temperature difference equal to Sa/2Eα, where Sa is the value obtained from the applicable design fatigue curve for the specified number of startup shutdown cycles, and E and α are the modulus of elasticity and the instantaneous coefficient of thermal expansion, respectively, at the mean value of the temperatures at the two points.

  The applicant stated that the maximum temperature difference between any two points, and the maximum temperature difference between adjacent points, occurs at the main steam line penetration, where an annular plate joins the penetration sleeve. The mean temperature of the insulated steam line is 530 °F, and the containment ambient temperature is 80 °F. The maximum temperature difference at this location is therefore 450 °F. Based on an assumed 120 full startup/shutdown cycles over 60 years, the allowable temperature difference was calculated to be 462 °F. The maximum temperature difference is smaller than the allowable temperature difference, and, therefore, this condition was shown to be satisfied.

- Condition 4, “Temperature Difference—Normal Service,” requires that the temperature difference in degrees F between any two adjacent points of the component during normal operation not exceed an allowable temperature difference equal to Sa/2Eα, where Sa is the value obtained from the applicable design fatigue curve for the total number of significant temperature difference fluctuations, and E and α are the modulus of elasticity and instantaneous coefficient of thermal expansion, respectively, at the mean value of the temperatures at the two points.

  The applicant stated in UFSAR Section 3.2.2.1.5 that during normal operation, the temperature in the main steam line fluctuates between 514 °F and 547 °F. The containment inside temperature fluctuates approximately plus or minus 20 °F from the mean. Conservatively assuming that these two temperature fluctuations occur totally out-of-phase and result in a maximum fluctuation range of 73 °F, and assuming 17,145 significant temperature difference fluctuations, the allowable temperature difference was calculated to be 77 °F. The maximum temperature fluctuation is smaller than the allowable temperature difference, and, therefore, this condition was shown to be satisfied.

- Condition 5, “Temperature Difference—Dissimilar Materials,” requires that for components fabricated from materials of differing moduli of elasticity and/or coefficients of thermal expansion, the total range of temperature fluctuations experienced by the component during normal operation shall not exceed the allowable temperature fluctuation $Sa/[2(E_1\alpha_1-E_2\alpha_2)]$, where Sa is the value obtained from the applicable design fatigue curve for the total specified number of significant temperature fluctuations. A fluctuation shall be considered significant if its total excursion exceeds the quantity $S/[2(E_1\alpha_1-E_2\alpha_2)]$, where S is the value obtained from the applicable design fatigue curve for 10^6 cycles.

The applicant stated that the only dissimilar material interface in a penetration occurs at the junction of a carbon steel sleeve and an austenitic stainless steel annular plate. Based on the material properties of the two metals at operating temperature, a temperature fluctuation was determined to be significant if it exceeds 81 °F. During normal operations, the temperature fluctuations at the junction of a penetration sleeve and an annular plate are less than this value. Therefore, there are no significant temperature fluctuations and this condition is shown to be satisfied.

- Condition 6, “Mechanical Loads,” requires that the specified full range of mechanical loads, excluding pressure but including pipe reactions, shall not result in load stresses whose range exceeds the Sa value from the applicable design fatigue curve for the total specified number of significant load fluctuations.

  The applicant stated that the only mechanical loads acting on the penetrations are dead, pressure, and seismic loads, and the corresponding piping reactions. Only seismic loads need be considered since dead loads are not cyclic. The applicant did a bounding calculation. The number of maximum stress cycles that was considered during a safe-shutdown earthquake event was 10. At 10 cycles, the corresponding value of Sa equals 550 ksi. The largest possible elastic peak stress, calculated as the product of the highest allowable primary plus secondary stress intensity 3 Sm for all materials considered in the penetrations, and the largest stress intensification factor specified in N-415.3, of value 5, was determined as 350 ksi. This peak stress is significantly less than the Sa, and, therefore, this condition is shown to be satisfied.

The staff has evaluated the responses to the RAIs and concludes that the applicant has provided a reasonable demonstration that the conditions for exclusion of a Section III fatigue analysis of the containment liner and liner penetrations have been met, in accordance with the provisions of ASME Section III, Subsection A, N-415.1, 1965.

In RAI 4.6-3, the staff requested that the applicant indicate whether the hot piping penetration assemblies contain bellows, and to provide the justification for not identifying fatigue of the bellows as TLAAs in accordance with 10 CFR 54.3. In response, the applicant stated that the hot and cold mechanical penetrations at Ginna Station contain bellows, which by design, do not perform a containment isolation function. The only functions of these bellows is to accommodate lateral and axial pipe movements. Therefore, the applicant concluded that fatigue of these bellows is not a TLAA as defined in 10 CFR 54.3. The staff agrees with the applicant’s conclusion.

4.6.3 Conclusions

On the basis of its review, the staff concludes that the applicant has demonstrated that the containment liner penetrations fatigue TLAA has been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii). The staff also concludes that the

UFSAR Supplement contains an appropriate summary description of the containment liner plate and penetrations fatigue TLAA evaluation for the period of extended operation, as reflected in the license condition, to satisfy 10 CFR 54.21(d). Therefore, the staff has reasonable assurance that the safety margins established and maintained in the containment liner plate and penetrations fatigue TLAA during the current operating term will be maintained during the period of extended operation, as required by 10 CFR 54.21(c)(1).

4.7 Other Plant-Specific Time-Limited Aging Analyses

There are certain plant-specific safety analyses that may have been based on an explicitly assumed 40-year plant life and may therefore be TLAAs. Pursuant to 10 CFR 54.21(c)(1), a license renewal applicant is required to evaluate TLAAs, as defined in 10 CFR 54.3. License renewal reviews focus on the period of extended operation.

The applicant has identified seven additional TLAAs for license renewal:

- containment liner stress
- containment tendon fatigue
- containment liner anchorage fatigue
- containment tendon bellows fatigue
- crane load cycle limit
- reactor coolant pump flywheel
- thermal aging of cast austenitic stainless steel

The staff's evaluation of these TLAAs is provided below.

4.7.1 Containment Liner Stress

4.7.1.1 Summary of Technical Information in the Application

The containment liner is fabricated from carbon steel plate conforming to ASTM A442-60T Grade 60 with a minimum yield stress of 32,000 psi and a buckling stress of 16,600 psi at operating conditions. The liner plate thickness is 1/4" for the base and 3/8" for the cylinder and dome. The applicant stated that the liner meridional stress due to initial prestressing was calculated as 4500 psi in compression. As a result of concrete strain due to shrinkage and creep, the liner stress was projected to increase to 14,100 psi at the end of 40 years. The creep and shrinkage strain that will occur at the end of the 60-year plant life has been evaluated, and the resulting compressive liner stress due to both time-dependent and non-time-dependent loads was determined to be 14,870 psi. The liner stress has thus been determined to be less than the liner buckling stress of 16,600 psi for the period of extended operation.

4.7.1.2 Staff Evaluation

Based on the values provided by the applicant, the staff finds the applicant's evaluation of the additional compressive stress induced by concrete shrinkage and creep into the liner reasonable and acceptable. The staff also concludes that, based on the information discussed above, the applicant has performed an acceptable TLAA to demonstrate that adequate margin against liner buckling will be maintained for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

4.7.1.3 Conclusions

On the basis of its review, the staff concludes that the applicant has demonstrated that the containment liner stress TLAA has been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii). The staff also concludes that the UFSAR Supplement contains an appropriate summary description of the containment liner stress TLAA evaluation for the period of extended operation, as reflected in the license condition, to satisfy 10 CFR 54.21(d). Therefore, the staff has reasonable assurance that the safety margins established and maintained in the containment liner stress TLAA during the current operating term will be maintained during the period of extended operation, as required by 10 CFR 54.21(c)(1).

4.7.2 Containment Tendon Fatigue

4.7.2.1 Summary of Technical Information in the Application

The applicant provided the following description of its containment tendon fatigue TLAA:

> A discussion of seismic considerations for tendons is provided in the Ginna UFSAR. Fatigue tests were conducted on tendon wire materials in 1960 by an independent testing lab. The tests indicated that the tendons were capable of withstanding over 2 million cycles at stress levels between 135 and 158 ksi. The test results were used to conclude that dynamic loads, considering especially pulsating loads resulting from an earthquake, do not jeopardize buttonhead anchorage. This discussion may not meet the definition of a TLAA as described in 10 CFR 54.3, however it has been included for conservatism.

Furthermore, the applicant asserts that the tendons were tested to 2 million cycles, which exceeds by many orders of magnitude the total cycles that could accumulate through multiple seismic events over 60 years.

Based on the qualitative analysis, the applicant concluded that the seismic fatigue evaluation remains valid through the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(I).

4.7.2.2 Staff Evaluation

Although the applicant indicated that tendon fatigue may not meet the definition of a TLAA as described in 10 CFR 54.3, the applicant performed the TLAA evaluation to be conservative. The cyclic loading testing is a part of the prequalification testing of the tendon anchorage hardware to ensure its integrity under normal fluctuating loads and occasional vibratory loads (due to design-basis seismic loads) induced in the hardware. The prequalification tests are marginally relevant to the TLAA, as the tests were not performed on the aged hardware components. These prequalification tests are required for all prestressing tendon systems utilized in the containments of nuclear power plants. Recognizing the requirements of prequalification tests and that the TLAA performed for the prestressing tendon force in

Section 4.5 of this LRA provides necessary information regarding the time-limited aging effects on prestressing tendon systems, the staff does not require a TLAA for tendon fatigue.

The applicant has summarized the TLAA supporting activities for the containment tendon fatigue in the UFSAR Supplement provided in Section A3.5.1 of the LRA. The description is identical to that provided in Section 4.7.4 of the LRA.

4.7.2.3 Conclusions

On the basis of the TLAA review of Section 4.7.2, “Containment Tendon Fatigue,” of the LRA, the staff concludes that the analysis reinforces the staff’s conclusion in Section 4.5 of this SER that the containment tendon system will perform its intended function during the extended period of operation.

4.7.3 Containment Liner Anchorage Fatigue

4.7.3.1 Summary of Technical Information in the Application

The applicant stated that a fatigue analysis of the fillet weld attaching the channel anchors to the containment liner was performed as part of the original design. The allowable fatigue stress of the attachment weld was set equal to the stress caused by static loading. This stress equals 13,600 psi and corresponds to 100,000 allowable stress cycles. The applicant also indicated that this analysis may not meet the definition of a TLAA as described in 10 CFR 54.3.

4.7.3.2 Staff Evaluation

In RAI 4.7.3-1, the staff requested that the applicant provide the design transients and corresponding cycles which generated the static stress of 13,600 psi in the fillet weld. The applicant stated that the fillet weld attaching the channel anchors to the liner was designed for 100,000 full stress cycles, which corresponds to 13,600 psi on the design fatigue curve for carbon steel. The only cyclic loads on the fillet weld are those caused by the temperature and pressure fluctuations in the containment. The static stress value bounds the stresses due to these fluctuations.

In RAI 4.7.3-2, the staff requested that the applicant provide the design code to which the fatigue analysis of the fillet welds was performed. In response, the applicant stated that the fillet welds were designed to AISC Specification, Section 1.7.2, and other non-ASME structural codes. The staff finds this acceptable because it conforms with industry practice for this vintage plant.

In RAI 4.7.3-3, the staff requested that the applicant provide justification for not applying a fatigue strength reduction factor to the static stress for determining the allowable cycles for the fillet weld. In response, the applicant stated that the static stress was taken as the allowable fatigue stress in the original containment design, in accordance with the design codes used to design the channel anchors. Therefore, a fatigue strength reduction factor was not applicable. This stress corresponds to 100,000 cycles, which correlates to more than 4 full stress cycles per day for 60 years. The pressure and temperature fluctuations in the containment are not of sufficient magnitude to cause four full cycles of design-basis stress at the liner anchorage weld every day. The original fatigue analysis therefore remains valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(I). The staff agrees with the applicant's assessment that the number of full pressure and temperature fluctuations will be less than 100,000 cycles for 60 years of plant operation.

In RAI 4.7.3-4, the staff requested the applicant to clarify why it thought this fatigue analysis may not meet the definition of a TLAA, as described in 10 CFR 54.3. In response, the applicant stated that this analysis was located in vendor calculations. It is not apparent that it was submitted to the NRC and made part of the Ginna CLB. Therefore, the sixth element for defining a TLAA may not have been met. The applicant indicated that it took a conservative approach when it evaluated this issue as a TLAA.

4.7.3.3 Conclusions

On the basis of its review, the staff concludes that the applicant has demonstrated that the containment liner anchorage fatigue analyses remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(I). The staff also concludes that the UFSAR Supplement contains an appropriate summary description of the containment liner anchorage fatigue evaluation for the period of extended operation to satisfy 10 CFR 54.21(d). Therefore, the staff has reasonable assurance that the safety margins established and maintained during the current operating term in the containment liner anchorage fatigue analysis will be maintained during the period of extended operation, as required by 10 CFR 54.21(c)(1).

4.7.4 Containment Tendon Bellows Fatigue

4.7.4.1 Summary of Technical Information in the Application

The applicant provided the following description of the TLAA related to the fatigue consideration of the containment tendon bellows:

> The allowable radial and vertical displacements of the containment stainless steel tendon bellows are given in the UFSAR and are limited to two cycles per year for the 40-year life of the plant. This limits the total number of allowable displacement cycles to 80. Since the completion of construction, displacements at the tendon bellows have occurred due to pressure testing and temperature changes in the cylindrical shell wall due to summer/winter conditions and reactor shutdown during refueling outages. [Furthermore]–this discussion may not meet the definition of a TLAA as described in 10 CFR 54.3, however it has been included for conservatism.

The applicant also stated, "assuming that 80 full cycles of allowable displacement results in a fatigue usage factor of 1.0, the actual fatigue usage factor over a 60-year period has been calculated to be much less than 0.01." Therefore, the applicant concluded that the original fatigue analysis remains valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(I).

4.7.4.2 Staff Evaluation

The Ginna containment is a unique containment for which the hinge formation of the containment shell has been deliberately designed. As part of the design, the applicant has provided stainless steel bellows in the tendon sheathing to alleviate any extraneous bending and shear forces. The applicant is prudent in performing a TLAA of the bellows for the period of extended operation.

In RAI 4.7.4-1, the staff requested the applicant to provide the UFSAR reference regarding the allowable radial and vertical displacements of the containment stainless steel tendon bellows and calculations showing the fatigue usage factor less than 0.01.

In response, the applicant provided the following information:

> The containment stainless steel tendon bellows were designed to the requirements of USAS B31.1 Code for pressure piping. Figure 3.8-18 is referenced in UFSAR Section 3.8.1.4.4.1. Figure 3.8-18 contains the following information:
>
> (1) Movements:
> Case (1)–From undeflected position vertically downward 0.14 inches
> Case (2)–From above position vertically upward 0.10 inches and simultaneous laterally 0.16 inches
> (2) Fatigue: Two cycles per year
> (3) Working Pressure: 60 psig
> Test Pressure: Hydrostatic at 150% of working pressure
> Pneumatic at 125% of working pressure
> (4) Maximum working temperature: 160 °F
> (5) Standard Specification: USAS B31.1 Code for Pressure Piping
> (6) Test two random assemblies for specified movements
>
> Based on this information, the total number of thermal cycles including those accumulated during the period of extended operation would not exceed the allowable number of cycles (7000) for a stress range reduction factor of 1.0 in the USAS B31.1 pressure piping code.
>
> A calculation of CUF for the tendon bellows for the period of extended operation was also performed as a TLAA in DA-CE-2002-016-07. This calculation is presented below:
>
> The allowable radial and vertical displacements of the containment stainless steel tendon bellows are given in UFSAR Figure 3.8-18 and are limited to two cycles per year for the 40 year life of the plant. This limits the total number of allowable displacement cycles to 80. Assume that 80 cycles of allowable displacement results in a fatigue usage factor of 1.0.
>
> From ASME Code Figure N-415(B) for stainless steel, the allowable alternating stress amplitude, Sa, for 80 cycles is 260 ksi. Assume that this is the peak stress produced in the bellows due to the combined effect of design basis vertical and radial displacements of 0.10" and 0.16" given in UFSAR Figure 3.8-18, and that this stress is directly proportional to the absolute sum of the displacements. Thus, Sa = 260 ksi is produced at an absolute displacement of 0.26".
>
> The absolute magnitude of the combined vertical and radial displacements that actually occur is 0.030" + 0.014" = 0.044". This displacement corresponds to a bellows stress level of (0.044/0.26)(260) = 44 ksi.
>
> The alternating stress intensity amplitude of 44 ksi corresponds to 40,000 cycles. The fatigue usage factor is 144/40,000 = 0.004.

> Therefore, the structural integrity of the tendon bellows will be maintained through the period of extended operation.

The applicant was requested to provide the bases for (1) 0.030 in (vertical) displacement, (2) 0.0014 in (radial) displacement, and (3) 144 cycles used in the final fatigue usage factor calculations.

In Attachment 3 of the applicant's letter dated July 16, 2003, the applicant provided a detailed analysis of how it arrived at the vertical and horizontal displacement, as well as a basis for using 144 cycles in the tendon bellows fatigue analysis. The analysis is based on the observed displacements of the containment wall during the structural integrity tests (SITs) performed in 1969 and 1996. In calculating the number of cycles of the bellows movements in 60 years, the applicant considered 4 SITs, 20 integrity leakage rate tests, 60 seasonal temperature variation cycles, and 60 shutdown/startup cycles. The staff considers the method of calculating the fatigue usage factor for the tendon bellows acceptable, as it utilizes the actual observations in establishing the bellows movements and conservative ways of calculating the number of cycles. The staff considers the issue relative to RAI 4.7.4-1 to be resolved and the fatigue analysis valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(I).

The applicant has summarized the TLAA supporting activities for the concrete containment tendon force in Section A3.5.2. The description is similar to that provided in Section 4.7.4 of the LRA, except that it provides the fatigue usage factor of 0.004 for the tendon bellows. The staff considers the description adequate for the UFSAR Supplement.

4.7.4.3 Conclusions

On the basis of the review of Section 4.7.4, "Containment Tendon Bellows Fatigue," of the LRA, the staff concludes that there is a reasonable assurance that the containment tendon bellows will perform their intended function during the extended period of operation, provided their aging degradation is managed or monitored. The staff also concluded that the fatigue analysis remains valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(I). Further, the UFSAR Supplement contains an appropriate summary description of the containment tendon bellows fatigue TLAA evaluation for the period of extended operation, as reflected in the license condition, to satisfy 10 CFR 54.21(d).

4.7.5 Crane Cycle Load Limits

4.7.5.1 Summary of Technical Information in the Application

The applicant stated that each of the estimated crane cycle numbers were compared to the design load cycles. They are all well below the upper design loading cycle limit. In addition, the average percent of the rated load lifted was well below the 50 percent level, relative to the design load cycles, as set forth in the design criteria.

Because the number of operating load cycles for the cranes will be less than the design cycles, and because the average percent of rated load lifted is less than 50 percent for the design load cycles, the applicant contended that the crane designs will remain valid for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(I).

4.7.5.2 Staff Evaluation

The method of review applicable to the crane cyclic load limit TLAA involves (1) reviewing the existing 40-year design basis to determine the number of load cycles considered in the design of each of the cranes in the scope of license renewal, and (2) developing 60-year projections for load cycles for each of the cranes in the scope of license renewal and comparing them with the number of design cycles for 40 years.

In RAI 4.7.5-1, the staff requested the applicant to provide the estimated number of load cycles and the assumptions used in the estimation. The applicant was also requested to provide the upper design loading cycle limit for each crane within the scope of license renewal.

In its response dated May 28, 2003, the applicant provided the requested data which were extracted from the applicant's design analysis document, DA-2002-016-03, "Containment Time-Limited Aging Analyses For License Renewal Calculation of Crane Load Cycles and Fatigue Evaluation." The data indicate that most loads are significantly below the capacity of cranes. Where the loads are near or comparable to the rated capacity of the cranes, the number of cycles is significantly below the design loading cycles, thereby reducing fatigue loading on the cranes.

The staff finds the applicant's response acceptable because the data provided by the applicant support its contention that the crane designs will remain valid for the period of extended operation.

Section 4.7.5 of the LRA states that the average percent of the rated load lifted is less than 50 percent for the design load cycles. In RAI 4.7.5-2, the staff requested the applicant to provide assurance that the percentage will not change during the period of extended operation.

In its response dated May 28, 2003, the applicant stated that the percentages are based on the types of loads the cranes are designed to lift versus their capacity. The applicant indicated that any projected load lifts above 50 percent capacity have a frequency that is only a small percentage of the design loading cycles. The applicant also indicated that the crane duty is not expected to change between now and 2029, and that any significant changes would be subject to engineering analysis. The staff finds the applicant's response satisfactory and acceptable because the data provided by the applicant support this assessment.

4.7.5.3 Conclusions

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1), that the analyses for the crane cycle load limit TLAA have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR Supplement contains an appropriate summary description of the metal fatigue TLAA evaluation for the period of extended operation, as reflected in the license condition, to satisfy 10 CFR 54.21(d). Therefore, the staff has reasonable assurance that the safety margins established and maintained during the current operating term will be maintained during the period of extended operation, as required by 10 CFR 54.21(c)(1).

4.7.6 Reactor Coolant Pump Flywheel

The function of the reactor coolant pump (RCP) in the RCS of a PWR plant is to maintain an adequate cooling flow rate by circulating a large volume of primary coolant water at high temperature and pressure through the RCS. A concern about overspeed of the RCP and its potential for failure led to the issuance of RG 1.14 in 1971. The regulatory position of RG 1.14 concerning ISI calls for an in-place ultrasonic volumetric examination of the areas of higher stress concentration at the bore and keyway at approximately 3-year intervals and a surface examination of all exposed surfaces and complete ultrasonic volumetric examination at approximately 10-year intervals. The flywheel inspection schedule is to coincide with the individual plant's ISI schedule as required by Section XI of the ASME Code.

In January 1996, Westinghouse submitted WCAP-14535, "Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination." This report, which provides engineering analysis based on fracture mechanics, is intended to eliminate RCP flywheel ISI requirements for all operating Westinghouse plants and some Babcock and Wilcox Plants. However, the NRC safety evaluation of WCAP-14535 stated, "The staff believes that even for flywheels meeting all the design criteria of RG 1.14, as modified in this SER, inspections should not be completely eliminated." The NRC safety evaluation went on to say—

> …the staff finds the following acceptable:
>
> (1) Licensees who plan to submit a plant-specific application of this topical report for flywheels made of SA 533 B material need to confirm that their flywheels are made of SA 533 B material. Further, licensees having Group-15 flywheels need to demonstrate that material properties of their A516 material is equivalent to SA 533 B material, and its reference temperature, RT_{NDT}, is less than 30 °F.
>
> (2) Licensees who plan to submit a plant-specific application of this topical report for their flywheels not made of SA 533 B or A516 material need to either demonstrate that their flywheel material properties are bounded by those of SA 533 B material, or provide the minimum specified ultimate tensile stress, S_u, the fracture toughness, K_{1c}, and the reference temperature, RT_{NDT}, for that material. For the latter, the licensees should employ these material properties, and use the methodology in the topical report, as extended in the two responses to the staff's RAI, to provide an assessment to justify a change in inspection schedule for their plants.
>
> (3) Licensees meeting either (1) or (2) above should either conduct a qualified in-place UT examination over the volume from the inner bore of the flywheel to the circle of one-half the outer radius or conduct a surface examination (MT and/or PT) of exposed surfaces defined by the volume of the disassembled flywheels once every 10 years. The staff considers this 10-year inspection requirement not burdensome when the flywheel inspection is conducted during scheduled ISI inspection or RCP motor maintenance. This would provide an appropriate level of defense in depth.

4.7.6.1 Summary of Technical Information in the Application

Westinghouse Topical Report WCAP-14535 presents an evaluation of the probability of failure over an extended operating period of 60 years. This report demonstrates that the flywheel design has a high structural reliability with very high flaw tolerance and negligible flaw crack extension over a 60-year service life. Based on WCAP-14535A, and in accordance with NRC recommendations, Rochester Gas and Electric Corporation (RG&E) requested and received a relief request from the NRC allowing it to revise the ISI frequency of flywheel examination to once every 10 years.

4.7.6.2 Staff Evaluation

By letter dated March 18, 1997, RG&E submitted for staff review its assessment of the plant-specific applicability of WCAP-14535 for Ginna. In Ginna's submittal, the licensee confirmed that its flywheels are made of SA 533 B material and that they do not belong to either Group 10 or Group 15 flywheels by WCAP-14535 definitions. Therefore, the plant-specific applicability of WCAP-14535 to RG&E had been established, and the 10-year inspection requirement with details specified in the NRC safety evaluation of WCAP-14535 were acceptable. Furthermore, fatigue crack growth calculations from WCAP-14535 showed that for 60 years of operation, crack growth from large postulated flaws in each of the flywheel groups is only a few mils. Therefore, the flywheel inspections completed prior to service are sufficient to ensure their integrity during service.

On the basis of the staff's evaluation described above, the summary description for the RCP flywheel TLAA in the UFSAR Supplement (LRA, Appendix A), as modified in a May 23, 2003, letter, provides an adequate description of this TLAA, as required by 10 CFR 54.21(d).

4.7.6.3 Conclusions

The staff has reviewed the TLAA on RCP flywheels. On the basis of this evaluation, the staff concludes that the Inservice Inspection Program requirements for the RCP flywheels at RG&E will continue to ensure that the effects of aging on the intended functions will be adequately managed for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii).

4.7.7 Thermal Aging of Cast Austenitic Stainless Steel

4.7.7.1 Summary of Technical Information in the Application

The applicant described the performance of TLAAs for thermal aging of cast austenitic stainless steel (CASS) for the period of extended operation in Section 4.7.7 of the LRA. Two TLAAs were performed which were documented respectively in WCAP-15837, "Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the R.E. Ginna Nuclear Power Plant for the License Renewal Program," and WCAP-15873, "A Demonstration of the Applicability of ASME Code Case –481 to the Primary Loop Casings of R.E. Ginna Nuclear Power Plant for the License Renewal Program."

In WCAP-15837, a leak before break (LBB) analysis was performed to demonstrate that leaks from through-wall cracks in RCS piping would be detected by plant monitoring systems before the cracks become unstable. The analysis considered the reduction of fracture toughness in CASS elbows due to thermal aging and assessed the crack stability in the reactor coolant piping for the period of extended operation. The results of the analysis showed that a significant margin exists between detectable flaw sizes and critical flaw sizes.

In WCAP-15873, a fracture mechanics analysis (flaw tolerance) was performed for the CASS RCP casings according to the requirements of ASME Code Case –481 for the period of extended operation. The results of the analysis showed that the stability criteria will be met with the fracture toughness of the pump casing materials in a fully aged condition. Therefore, for the ISI of CASS pump casings at the Ginna Station, the alternative visual examinations as delineated in Code Case –481 can be performed in lieu of the volumetric examinations required by ASME Code, Section XI.

4.7.7.2 Staff Evaluation

Thermal aging refers to the gradual change in the microstructure and properties of a susceptible material due to its exposure to elevated temperature for an extended period of time. Thermal aging may result in a reduction of the fracture toughness of a susceptible material, such as CASS, since the thermal aging embrittlement effect (loss of fracture toughness) is a time-dependent phenomena. The associated aging effect requires a TLAA to ensure that it will be adequately managed through the extended period of operation.

To support its review of Ginna's LRA, the staff requested additional information from the applicant. In RAI 4.7.7-1, the staff requested the applicant to confirm whether the two Westinghouse reports (WCAP-15837 and WCAP-15873) referenced in Section 4.7.7 have been submitted to the NRC for review and approval. If these reports have not been reviewed and approved by the NRC, the staff requested the applicant to submit the reports in support of Ginna's LRA. In response to the staff's RAI, the applicant submitted two copies each of the Proprietary Class 2 Westinghouse Topical Reports WCAP-15873, May 2002, and WCAP-15837, April 2002. In addition, the nonproprietary versions of these topical reports dated May 2003 were also submitted.

The Westinghouse Topical Report WCAP-15837 provides a plant-specific LBB analysis for RCS piping at the Ginna Station through the period of extended operation (60 years). The staff has completed the review of WCAP-15837 and has resolved all concerns regarding the number of years for which the fatigue crack growth analysis was performed and the CASS material degradation due to aging. The NRC staff's review confirmed that the fatigue crack growth analysis in WCAP-15837 was based on thermal transients of 60 years, and is therefore appropriate through the expiration of the extended operating period for Ginna. For the concern about the thermal aging of RCS primary loop piping and components made from CASS, the staff has verified that the applicant considered appropriate, fully-aged toughness for CASS. Based on the above evaluation, the staff agrees with the applicant's conclusion that this TLAA is in accordance with 10 CFR 54.21(c)(1)(ii), and the LBB application for the primary loop piping and components is acceptable for the period of extended operation.

The purpose of the flaw tolerance analysis, as documented in Westinghouse Topical Report WCAP-15873, is to support the application of Code Case –481 for the ISI examination of the

RCP casings at the Ginna Station. Code Case –481 allows the performance of visual examination of cast austenitic pump casing in lieu of volumetric examination.

In response to RAI B2.1.34-1, the applicant stated that the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program is consistent with the guidelines in AMP XI.M12 of NUREG-1801. AMP XI.M12 states that the existing ASME Section XI requirements, including the alternative requirements of ASME Code Case –481 for pump casings, are adequate for all pump casings and valve bodies. The program element for detection of aging effects also states that for pump casings, valve bodies, and "not susceptible" piping, no additional inspection or evaluations are required to demonstrate that the material has adequate fracture toughness.

The staff notes that the applicant's ASME Code, Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program is required to be updated by the applicant and reviewed by the staff every 10-year interval. The acceptability of using Code Case –481 as an alternative requirement for the ISI of pump casing will be evaluated by the staff during the review of the applicant's Inservice Inspection Program, which is submitted for NRC approval every 10-year interval. Therefore, it is more appropriate for the staff to review the applicant's fracture mechanics analysis during the staff's review of the applicant's Inservice Inspection Program. Based on the consideration discussed above, the staff has determined that there is no need for the staff to review the applicant's fracture mechanics analysis, as documented in WCAP-15873, to support the use of Code Case –481 for ISI of pump casing for the applicant's LRA as would otherwise be mandated by 10 CFR 54.21(c)(1).

The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program. The staff finds the subject supplement acceptable with the exception that the second paragraph of Section A3.2 pertaining to the discussion of the Westinghouse Topical Report WCAP-15873 should be deleted because the staff will not review this report for the applicant's LRA, as discussed above.

4.7.7.3 Conclusions

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that the TLAA on thermal aging of CASS RCS components remains valid through the period of extended operation. The staff also concludes that the UFSAR Supplement contains an adequate summary description (pending editorial changes as stated above) of the TLAA on thermal aging of CASS RCS components for the period of extended operation, as required by 10 CFR 54.21(d). Therefore, the staff has reasonable assurance that the safety margins established and maintained during the current operating term for the primary reactor coolant loop piping will be maintained through the period of extended operation for the Ginna Station.

4.8 Evaluation Findings

The staff has reviewed the information in Section 4 of the LRA. On the basis of its review, the staff concludes that the applicant has provided an adequate list of TLAAs, as defined in 10 CFR 54.3. Further, the staff concludes that the applicant has demonstrated that the

TLAAs (1) will remain valid for the period of extended operation, as required by 10 CFR 54.21(c)(1)(I), (2) have been projected to the end of the period of extended operation, as required by 10 CFR 54.21(c)(1)(ii), or (3) the aging effects will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(c)(1)(iii). In addition, the staff concludes that there are no plant-specific exemptions in effect that are based on TLAAs, as required by 10 CFR 54.21(c)(2). On this basis, the staff has reasonable assurance that the aging effects associated with the structures and components subject to TLAAs will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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5. REVIEW BY THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

The Advisory Committee on Reactor Safeguards (ACRS) will review the portion of the R.E. Ginna Nuclear Power Plant (Ginna) license renewal application (LRA) related to Title 10, Part 54, of the *Code of Federal Regulations* (10 CFR Part 54). The ACRS Subcommittee on Plant License Renewal will continue its detailed review of the LRA after this report is issued. Rochester Gas & Electric Corporation and the staff will meet with the full advisory committee to discuss issues associated with the review of the LRA. After the ACRS completes its review of the Ginna LRA and safety evaluation report (SER), the full committee will issue a report discussing the results of its review. This report will be included in an update to this SER. The staff will address any issues and concerns identified in that report.

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6. CONCLUSIONS

The staff reviewed the R.E. Ginna Nuclear Power Plant license renewal application in accordance with Commission regulations and the“Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants” (NUREG-1800), dated July 2001. In accordance with Title 10, Section 54.29 of the *Code of Federal Regulations* (10 CFR 54.29), the staff identifies the standards for issuance of a renewed license.

On the basis of its evaluation of the application as discussed above, the staff has determined that the requirements of 10 CFR 54.29(a) have been met.

The staff notes that any requirements of Subpart A of 10 CFR Part 51 are documented in NUREG-1437, Supplement 14, “Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Regarding R.E. Ginna Nuclear Power Plant,” dated February 6, 2004.

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APPENDIX A
COMMITMENT LISTING

During the review of the Ginna license renewal application by the NRC staff, the applicant made commitments to provide aging management programs to manage the aging effects of structures and components prior to the extended period of operation, as well as other information. The following table lists these commitments, along with the implementation schedule and the location of the commitment.

ITEM NUMBER	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
1	Submit new pressure-temperature limit curves.	December 2004	LRA Section 4.2.3; Letter 7/30/2002; and Letter 7/30/2003
2	Implement a Fatigue Monitoring Program to confirm that the number of operating cycles (causing fatigue) are fewer than the plant design cycles.	June 2004	LRA Section 4.3.1; Letter 7/30/2002; and Letter 7/30/2003
3	Provide an assessment of fatigue usage for nuclear sampling system B31.1 piping, for the period of extended operation.	Completed	LRA Section 4.3.2; Letter 7/30/2002; and Letter 7/30/2003
4	Provide a baseline nondestructive examination for the pressurizer surge line by inspecting all circumferential welds, and develop a methodology to employ NRC-approved augmented inservice inspection for pressurizer surge line, or recalculate to determine acceptable cumulative usage factor, or repair/replace surge line or subcomponents, as necessary.	Completed reanalysis	LRA Section 4.3.7; Letter 7/30/2002; and Letter 7/30/2003

ITEM NUMBER	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
5	Complete environmental qualification (EQ) calculations to extend the qualified life of EQ components from 40 to 60 years, for those components using TLAA criteria of 10 CFR 54.21(c)(ii).	Completed	LRA Section 4.4; Letter 7/30/2002; and Letter 7/30/2003
6	Retension 23 containment tendons as part of the 2005 tendon testing tendon program.	May 2005	LRA Section 4.5; Letter 7/30/2002; and Letter 7/30/2003
7	Perform one-time inspections of selected plant equipment to verify that current plant aging management programs are effective in managing the effects of aging.	Prior to September 2009	LRA Sections B.2.1.1; B.2.1.7; and B.2.1.21; Letter 7/30/2002; and Letter 7/30/2003
8	Enhance the Boric Acid Corrosion Surveillance Program to include all susceptible components (e.g., carbon/low-alloy steel, copper) potentially exposed to boric acid leaks.	Completed	LRA Section B.2.1.6; Letter 7/30/2002; and Letter 7/30/2003
9	Develop a program to periodically assess the condition of non-EQ cables in adverse localized environments.	Completed	LRA Section B.2.1.11; Letter 7/30/2002; and Letter 7/30/2003
10	Replace or test a representative sample of fire water system sprinklers that have been in service for up to 50 years.	Prior to 2016	LRA Section B.2.1.14; Letter 7/30/2002; and Letter 7/30/2003
11	Develop a Reactor Vessel Head Penetration Inspection Program, in concert with industry initiatives.	Ongoing initiative with NEI and MRP	LRA Section B.2.1.26; Letter 7/30/2002; and Letter 7/30/2003
12	Participate with industry in helping to develop augmented inspection techniques to detect fine cracks and other changes in dimension in nonbolted components of the reactor vessel internals.	Ongoing initiative with NEI and MRP. (Superseded by commitment #31)	LRA Section B.2.1.27; Letter 7/30/2002; and Letter 7/30/2003

ITEM NUMBER	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
13	Enhance Structures Monitoring Program to include all structures within the scope of license renewal, and provide additional guidance for detecting aging effects.	Completed	LRA Section B.2.1.32; Letter 7/30/2002; and Letter 7/30/2003
14	Enhance Systems Monitoring Program to include all systems within the scope of license renewal and provide additional guidance for detecting aging effects.	June 2004	LRA Section B.2.1.33; Letter 7/30/2002; and Letter 7/30/2003
15	Add the house heating boiler and associated components in screenhouse as requiring aging management review.	Prior to September 2009	Response to RAI 2.1-4; and Letter 5/13/2003
16	Locations judged to be potentially susceptible to thermal fatigue will be included in the sample population of small bore piping to be examined by appropriate volumetric technique.	Prior to September 2009	Response to RAI 3.2.1-1; and Letter 5/13/2003
17	The pressurizer manway stainless steel insert will receive a visual and surface examination as part of the applicant's Inservice Inspection Program to detect potential stress-corrosion cracking.	Prior to September 2009	Response to RAI 3.2.2-5; and Letter 5/13/2003
18	Add System Monitoring as an aging management program applicable to the pipe represented by Table 3.4-2, line number (42)	Prior to September 2009	Response to RAI 3.3-2; and Letter 5/27/2003
19	Develop an engineering guidance document that will direct inspections to evaluate galvanic corrosion at susceptible locations in a raw (service) water environment.	Prior to September 2009	Response to RAI 3.5-8; and Letter 5/27/2003
20	Develop an aging management program basis document to periodically measure insulation resistance of nuclear instrumentation system and high range radiation monitoring circuits	Prior to September 2009	Response to RAI 3.7-3; and Letter 6/10/2003

ITEM NUMBER	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
21	Modify technical specifications to incorporate specific particulate testing requirements for diesel generator fuel oil, and eliminate use of ASTM D4176	Prior to September 2009 (Superseded by commitment #40)	Response to C-RAI B2.1.16-1; and Letter 6/10/2003
22	Thermographic inspections of 34.5 kV transformer yard components are to be performed at least once per refueling cycle while the components are energized.	Prior to September 2009	Response to C-RAI 3.7-6(a); and Letter 7/16/2003
23	Perform visual inspections and ultrasonic testing thickness measurements of the containment liner during 2005 RFO.	2005 RFO	Response to C-RAI B2.1.3-3; and Letter 7/16/2003
24	Perform hardness tests, if feasible, on emergency diesel generator jacket water coolers and lube oil coolers channel heads.	2005 RFO	Response to C-RAI B2.1.29; and Letter 7/16/2003
25	Perform visual inspections of phase bus.	Prior to 2012	Response to C-RAI 3.7-5; and Letter 7/16/2003
26	Revise surveillance capsule withdrawal schedule and implement operating restrictions when capsule is withdrawn.	RFO 2005, RFO 2009 (Superseded by commitment #38)	Response to C-RAI 4.2-1; and Letter 7/30/2003
27	Perform two structural integrity tests at design pressure during period of extended operation.	2015 & 2026	Response to C-RAI 3.6-1; and Letter 7/30/2003
28	Reexamine liner and restore thickness if below acceptance criteria.	2005	Response to C-RAI B2.1.3-3(1); and Letter 7/30/2003

ITEM NUMBER	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
29	Include measurement of voltage between reference cells and rock anchors into Periodic Surveillance and Preventive Maintenance Program.	Prior to 2005	Response to C-RAI 3.5-8; and Letter 7/30/2003
30	Define selection criteria, sample size, and periodicity of inspections for fire system piping	Prior to September 2009	Response to AMP audit finding; and Letter 9/16/03
31	Submit Reactor Vessel Internals Program for staff review and approval.	September 2007 (Supersedes commitment #12)	Response to OI 3.1.2.3.3-1; and Letter 12/19/03
32	Add component cooling water makeup water piping, valves and pumps from the refueling water storage tank to the spent fuel pool into the scope of license renewal.	July 2004	Response to OI 2.3.3.2-1; and Letter 12/9/03
34	Perform joint resistance tests when visual inspections of PVC boots or other materials of construction indicate that the joint may be overheating.	July 2004	Response to OI 3.6-1; and Letter 12/9/03
35	Add spent fuel pool (SPF) makeup path from refueling water storage tank to the SFP into scope of license renewal.	July 2004	Response to OI 2.3.3.3-1; and Letter 12/9/03
36	Add fire service water (SW) booster pump and associated valves and piping back to the SW system into the scope of license renewal.	July 2004	Response to OI 2.3.3.6-1; and Letter 12/9/03
37	Add medium-voltage cables M0089 and M0108 into the scope of license renewal and develop aging management program consistent with NUREG-1801, Section XI.E3.	July 2004	Response to OI 2.5-1; and Letter 12/9/03

ITEM NUMBER	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
38	Withdraw surveillance capsule in Spring 2005 and submit test report of results within one year, in accordance with 10 CFR 50, App. H, paragraph IV.A. Withdraw last surveillance capsule shortly after accumulating fluence equivalent to 80 years of operation.	Spring 2005 2011 RFO (Supersedes commitment #26)	Response to OI B2.1.28-1; and Letter 12/9/03
39	Perform inspections of thimble tubes for wear and stress-corrosion cracking (SCC) each refueling outage. VT-1 quality inspect stainless steel fillet weld joining the bottom mounted instrument (BMI) guide tube to the end of each BMI penetration, as well as the 82/182 weld between the SS safe end and the lower penetration nozzle, each refueling outage.	RFOs beginning in 2005: wear of thimble tubes RFOs beginning in 2009; SCC of thimble tubes RFOs beginning in 2005	Response to OI B2.1.36-1; and Letter 12/9/03
40	Submit License Amendment Request to incorporate specific particulate testing for diesel generator fuel oil, ASTM D2276 (or its successor), and eliminate the need for the “clear and bright” method of ASTM D4176.	December 2004 (Supersedes commitment #21)	Response to CI 3.3.2.3.4-1; and Letter 12/9/03

APPENDIX B
CHRONOLOGY

This appendix contains a chronological listing of routine licensing correspondence between the U.S. Nuclear Regulatory Commission (NRC) staff and Rochester Gas & Electric Corporation (RG&E), regarding the staff's review of the R.E. Ginna Nuclear Power Plant (Ginna), License Renewal Application (LRA) (Docket No. 50-244).

April 17, 2002	In a letter (signed by O. Tabatabai), the NRC issued a summary of a meeting held on March 27, 2002, between the NRC and RG&E regarding RG&E's plans for submitting its LRA for Ginna. ACN: ML 021120135
July 30, 2002	In a letter (signed by R. Mecredy), RG&E submitted its license renewal application for the R.E. Ginna Nuclear Power Plant. In its submittal, RG&E provided five copies of the application. ACN: ML 022210378
August 19, 2002	In a letter (signed by J. Cushing), the NRC acknowledged receipt of the application for the R.E. Ginna Nuclear Power Plant. ACN: ML 022320189
September 12, 2002	In a letter (signed by J. Cushing), the NRC issued a summary of a public meeting between the staff and RG&E representatives. The meeting was held on August 27, 2002, to discuss the Ginna LRA. ACN: ML 022560192
September 13, 2002	In a letter (signed by P.T. Kuo), the NRC determined that RG&E had submitted sufficient information that was acceptable for docketing, in accordance with 10 CFR 54.19, 10 CFR 54.22, 10 CFR 54.23, and 10 CFR 51.53(c). ACN: ML 022560467
November 4, 2002	In a letter (signed by R. Mecredy), RG&E provided information to the NRC regarding the Fatigue Pro automated fatigue monitoring system. ACN: ML 023180237
November 12, 2002	In a letter (signed by R. Arrighi), RG&E requested that the compact disc (CD-ROM) "containing the RG&E review tools" be withheld from public disclosure pursuant to 10 CFR 2.790. ACN: ML 023160515
November 19, 2002	In a letter (signed by R. Arrighi), the NRC issued a meeting summary regarding review of equipment environmental qualification calculations for R.E. Ginna Nuclear Power Plant. ACN: ML 02320333
November 21, 2002	In a letter (signed by R. Arrighi), the NRC issued a revision to the schedule for reviewing the R.E. Ginna LRA. ACN: ML 023300045
November 21, 2002	In a letter (signed by R. Mecredy), RG&E provided information regarding topical reports used in its LRA for time-limited analyses. ACN: ML 023310196

November 22, 2002	In a letter (signed by R. Arrighi), the NRC issued a summary of a telephone conference between the staff and RG&E representatives. This telephone conference was held on October 31, 2002, to discuss RG&E's use of the Fatigue Pro automated fatigue monitoring system. ACN: ML 023310349
January 14, 2003	In a letter (signed by R. Arrighi), the NRC issued a summary of a meeting held on December 17, 2002, regarding the proposed fatigue monitoring program at the R.E. Ginna Nuclear Power Plant. ACN: ML 030140450
January 22, 2003	In a letter (signed by R. Arrighi), the NRC issued a summary of a telephone conference between the staff and RG&E representatives. This telephone conference was held on November 26, 2003, to discuss RG&E's responses to draft requests for additional information (D-RAI) concerning the Ginna LRA. ACN: ML 030220041
March 5, 2003	In a letter (signed by R. Arrighi), the NRC issued a summary of a telephone conference between the staff and RG&E representatives. This telephone conference was held on January 15 and 21, 2003, to discuss RG&E's responses to D-RAIs concerning the Ginna LRA. ACN: ML 030640318
March 21, 2003	In a letter (signed by R. Arrighi), the NRC issued a request for additional information for the review of the Ginna LRA. ACN: ML 030830079
March 28, 2003	In a letter (signed by R. Arrighi), the NRC issued a revision to the request for additional information for the review of the Ginna LRA. ACN: ML 030900518
April 2, 2003	In a letter (signed by R. Arrighi), the NRC issued a summary of a meeting between the staff and RG&E held on February 3 and 4 to discuss D-RAIs. ACN: ML 030930638
April 11, 2003	In a letter (signed by R. Mecredy), RG&E provided a response to RAIs 4.2.1-1 and 4.2.2 -1. ACN: ML 031070329
May 13, 2003	In a letter (signed by R. Mecredy), RG&E provided responses to 133 of the 224 LRA RAIs. ACN: ML 031410763
May 16, 2003	In a letter (signed by R. Subbaratnam), the NRC issued a summary of a telephone conference between the staff and RG&E representatives. This telephone conference was held on April 23, 2003, to discuss RG&E's responses to RAIs 4.2.1 -1 and 4.2.2-1. ACN: ML 031390404
May 23, 2003	In a letter (signed by R. Mecredy), RG&E provided responses to an additional 29 of the 224 LRA RAIs. ACN: ML 031530203

June 3, 2003	In a letter (signed by M. Cora), the NRC issued a summary of a meeting between the staff and RG&E held on May 22, 2003, to discuss the pressurizer surge line 60-year fatigue analysis. ACN: ML 031540738
June 3, 2003	In a letter (signed by R. Mecredy), RG&E provided copies of Westinghouse Topical Reports WCAP-15873 and WCAP-15837 in response to LRA RAI 4.7.7 -1. ACN: ML 031610765 and ML 031610768
June 10, 2003	In a letter (signed by R. Mecredy), RG&E provided the remaining responses to LRA RAIs. ACN: ML 031690230
July 11, 2003	In a letter (signed by R. Mecredy), RG&E provided responses to LRA RAI clarifications. ACN: ML 031990231
July 16, 2003	In a letter (signed by R. Mecredy), RG&E provided additional responses to LRA RAI clarifications. ACN: ML 031970009
July 22, 2003	In a letter (signed by R. Arrighi), the NRC issued Revision 2 to the schedule for reviewing the Ginna LRA. ACN: ML 032040005
July 30, 2003	In a letter (signed by R. Mecredy), RG&E provided the remaining responses to LRA RAI clarifications, and provided a completion schedule for commitments provided in the LRA dated July 30, 2002. ACN: ML 032180458
July 30, 2003	In a letter (signed by R. Mecredy), RG&E provided a supplement to the LRA in accordance with 10 CFR 54.21(b) to identify changes to the current licensing basis. ACN: ML 032180454
August 1, 2003	In a letter (signed by R. Mecredy), RG&E provided a supplement to its correspondence dated July 30, 2003, regarding the annual supplement to the Ginna LRA per 10 CFR 54.21(b). ACN: ML 032200361
August 1, 2003	In a letter (signed by R. Arrighi), the NRC notified RG&E of its determination that the WCAPs submitted on June 3, 2003, contained proprietary commercial information and should be withheld from public disclosure. ACN: ML 032250102
August 6, 2003	In a letter (signed by R. Mecredy), RG&E provided a response to RAI clarification 3.7-3. ACN: ML 032320191
August 8, 2003	In a letter (signed by R. Mecredy), RG&E provided a response to RAI clarifications 4.3.7-1 and B2.1.14. ACN: ML 032310172

August 26, 2003	In a letter (signed by R. Subbaratnam), the NRC issued a summary of a telephone conference between the staff and RG&E representatives. This telephone conference was held on July 10, 2003, to discuss RG&E's responses to RAIs. ACN: ML 032390323
September 16, 2003	In a letter (signed by R. Arrighi), the NRC issued clarifications to RAIs for the review of the Ginna LRA. ACN: ML 032591149
September 16, 2003	In a letter (signed by R. Mecredy), RG&E provided a response to RAIs. ACN: ML 032661304
September 24, 2003	In a letter (signed by J. Rowley) the NRC issued a summary of a telecommunication between the staff and RG&E dealing with the scoping of SSCs within the spent fuel pool and firewater systems relative to the Ginna LRA. ACN: ML 032670809
October 8, 2003	In a letter (signed by J. Rowley), the NRC issued a revision to the schedule for reviewing the R.E. Ginna LRA. ACN: ML 032830114
December 9, 2003	In a letter (signed by R. Mecredy), RG&E provided a response to open and confirmatory items identified in the Ginna SER with open items. ACN: ML 033510057
December 19, 2003	In a letter (signed by R. Mecredy), RG&E provided its final responses to open and confirmatory items identified in the Ginna SER with open items. ACN: ML 040020019
January 9, 2004	In a letter (signed by R. Mecredy), RG&E provided a clarification to Confirmatory Item CI 2.3.3.5-1 identified in the Ginna SER with open items. ACN: ML 040150396

APPENDIX C
PRINCIPAL CONTRIBUTORS

NAME	RESPONSIBILITY
R. Arrighi	Project Manager
H. Ashar	Mechanical Engineering
S. Bailey	Mechanical Engineering
P. Balmain	Quality Assurance
T. Chan	Management Supervision
S. Chaudhary	Region 1 Inspector
P. Chen	Technical Support
L. Cheung	Region 1 Inspector
S. Chey	Administration Support
S. Coffin	Management Supervision
K. Coyne	Quality Assurance
J. Cushing	Project Manager
B. Elliot	Materials Engineering
J. Fair	Mechanical Engineering
E. Forrest	Plant Systems
D. Frumkin	Fire Protection
G. Galletti	Quality Assurance
R. Goel	Plant Systems
M. Hartzman	Civil Engineering
C. Holden	Management Supervision
D. Jackson	Plant Systems
S. Jones	Plant Systems
C. Khan	Materials Engineering
W. Koo	Materials Engineering
P. Kuo	Management Supervision
J. Lazevnick	Electrical Engineering
A. Lee	Mechanical Engineering
S. Lee	Management Supervision
J. Lehning	Plant Systems
Y. Li	Mechanical Engineering
A. Lohmeier	Region 1 Inspector
C. Long	Materials Engineering
L. Lund	Management Supervision
J. Ma	Mechanical Engineering
K. Manoly	Management Supervision
M. Modes	Region 1 Inspector
C. Munson	Civil Engineering
M. Murphy	Chemical Engineering
K. Parcheski	Chemical Engineering
P. Prakash	Materials Engineering

J. Pulsipher	Plant Systems
J. Rajan	Civil Engineering
M. Razzaque	Reactor Systems
E. Reichelt	Materials Engineering
J. Rowley	Project Manager
S. Saba	Electrical Engineering
L. Scholl	Region 1 Inspector
T. Steingass	Materials Engineering
J. Strnisha	Mechanical Engineering
R. Subbaratnam	Project Manager
O. Tabatabai	Project Manager
D. Terao	Management Supervision
T. Terry	Technical Support
D. Thatcher	Management Supervision
H. Wagage	Plant Systems
S. Weerakkady	Management Supervision
C. Wu	Mechanical Engineering

CONTRACTORS

Contractor	**Technical Area**
Information Systems Laboratories	Scoping and Screening

APPENDIX D
REFERENCES

This appendix contains a listing of references used in preparing the safety evaluation report during the review of the license renewal application for the R.E. Ginna Nuclear Power Plant (Docket Number 50-244).

American Society of Mechanical Engineers (ASME)

ASME Boiler and Pressure Vessel Code, Section III, Subsection NF.

ASME Boiler and Pressure Vessel Code, Section XI, Rules for Inservice Inspection of Nuclear Power Plant Components.

ASME Boiler and Pressure Vessel Code, as modified by Code Case N-481.

CSUPP-ASME(CS)-EXT (structural carbon steel used in NSSS pipe and component supports that is outdoors (i.e., exposed to the weather)).

Code of Federal Regulations (CFR)

10 CFR 50.49, “Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants.”

10 CFR 50.55a, “Codes and Standards.”

10 CFR 50.60, “Acceptance Criteria for Fracture Prevention Measures for Light-Water Nuclear Power Reactors for Normal Operation.”

10 CFR 50.61, “Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events.”

10 CFR 50.62, “Requirements for Reduction of Risk from Anticipated Transients Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants.”

10 CFR 50.63, “Loss of All Alternating Current Power.”

10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.”

10 CFR Part 50 Appendix G, “Fracture Toughness Requirements.”

10 CFR Part 50, Appendix H, “Reactor Vessel Material Surveillance Program Requirements.”

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NRC Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors," July 26, 1988.

NRC Bulletin 96-02, "Movement of Heavy Loads Over Spent Fuel, Over Fuel in the Reactor Core, or Over Safety-Related Equipment," dated April 11, 1996.

NRC Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and RCS Pressure Boundary Integrity."

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Correspondence

U.S. NRC Letter dated August 19, 1985 from John A. Zwolinski to R.W. Kober.

U.S. NRC Letter from Johnson to Mecredy, "Ginna Flaw Indication in the Reactor Vessel Inlet Nozzle Weld—1989 Reactor Vessel Examination (TAC No. 71906)," July 7, 1989.

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