GRAND GULF NUCLEAR GENERATING STATION
Updated Final Safety Analysis Report (UFSAR)

APPENDIX A

UPDATED FINAL SAFETY ANALYSIS REPORT SUPPLEMENT

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A AGING MANAGEMENT PROGRAMS AND ACTIVITIES

The GGNS license renewal application (Reference A.3-1) and information in subsequent related correspondence provided sufficient basis for the NRC to make the findings required by 10 CFR 54.29 (Final Safety Evaluation Report) (Reference A.3-2). As required by 10 CFR 54.21(d), this UFSAR supplement contains a summary description of the programs and activities for managing the effects of aging (Section A.1) and a description of the evaluation of time-limited aging analyses for the period of extended operation (Section A.2). The period of extended operation is the 20 years after the expiration date of the original operating license.

A.1 AGING MANAGEMENT PROGRAMS

The integrated plant assessment for license renewal identified aging management programs necessary to provide reasonable assurance that components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis (CLB) for the period of extended operation. This section describes the aging management programs and activities required during the period of extended operation. Aging management programs will be implemented prior to entering the period of extended operation.

GGNS quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR 50, Appendix B. The GGNS Quality Assurance Program applies to safety-related structures and components. Corrective actions and administrative (document) control for both safety-related and nonsafety-related structures and components are accomplished in accordance with the established GGNS Corrective Action Program and Document Control Program and are applicable to all aging management programs and activities during the period of extended operation. The confirmation process is part of the Corrective Action Program and includes reviews to assure adequacy of corrective actions, tracking and reporting of open corrective actions, and review of corrective action effectiveness. Any follow-up inspection required by the confirmation process is documented in accordance with the Corrective Action Program. The corrective action, confirmation process, and administrative controls of the GGNS (10 CFR Part 50, Appendix B) Quality Assurance Program are applicable to all aging management programs and activities during the period of extended operation.

The Operating Experience Program (OEP) and the Corrective Action Program (CAP) help to assure continued effectiveness of aging management programs through evaluations of operating experience. The OEP implements the requirements of NRC NUREG-0737, Clarification of TMI Action Plan Requirements, Section I.C.5, and evaluates site, Entergy fleet, and industry operating experience for impact on GGNS. The CAP implements the requirements of 10 CFR 50, Appendix B, Criterion XVI and is used to evaluate and effect appropriate actions in response to operating experience relevant to GGNS that indicates a condition adverse to quality or a non-conformance.

A.1.1 115 kV Inaccessible Transmission Cable Program

The 115 kV Inaccessible Transmission Cable Program manages the effects of aging on the 115 kV inaccessible transmission cable systems. The program includes periodic actions to prevent

inaccessible transmission cables from being exposed to significant moisture. In this program, inaccessible 115 kV transmission cables exposed to significant moisture will be tested at least once every six years to provide an indication of the condition of the cable insulation properties. Test frequencies may be adjusted based on test results and operating experience. The specific type of test will be a proven test for detecting deterioration of the cable insulation. The program includes periodic inspections for water accumulation in manholes at least once every year (annually). In addition to the periodic manhole inspections, manhole inspection for water after events, such as heavy rain or flooding will be performed. Inspection frequency will be increased as necessary based on evaluation of inspection results. The corrective action program will be entered and an engineering evaluation will be performed when the test or inspection acceptance criteria are not met.

This program will be implemented prior to the period of extended operation. The first cable tests and manhole inspections are to be completed prior to the period of extended operation.

A.1.2 Aboveground Metallic Tanks Program

The Aboveground Metallic Tanks Program includes outdoor tanks situated on soil or concrete. The program includes preventive measure to mitigate corrosion by protecting the external surfaces of steel components per standard industry practice including the use of sealant or caulking at the concrete to tank interface of outdoor tanks. External visual examinations (supplemented with physical manipulation of caulking or sealant) are performed to monitor degradation of uncoated surfaces and of protective paint, coating, and caulking, or sealant. Surface exams are conducted to detect cracking when susceptible materials are used (e.g., stainless steel, aluminum). A sample of the external surfaces of insulated tanks are inspected. Internal visual and surface (when necessary to detect cracking) examinations are conducted as well as measuring the thickness of the tank bottoms to ensure that significant degradation is not occurring and that the component intended function is maintained during the period of extended operation.

The following table provides tank inspection details.[1]

Material	Environment	AERM	Inspection Technique[2]	Inspection Frequency
Inspections to identify degradation of inside surfaces of tank shell, roof[3], and bottom Inside Surface (IS), Outside Surface (OS)[4, 5]				
Stainless steel	Treated water	Loss of material	Visual from IS or volumetric from OS[6]	One-time inspection conducted in accordance with Section 8.1.33[7]
Inspections to identify degradation of external surfaces of tank roof, tank shell, and bottom not exposed to soil or concrete[8]				
Stainless steel	Air-outdoor	Loss of material	Visual from OS	Each refueling outage interval

		Cracking	Surface[9, 10]	Each 10·year period starting 10 years before the period of extended operation
Inspections to identify degradation of external surfaces of tank bottoms and tank shells exposed to soil or concrete				
Stainless steel	Soil or concrete	Loss of material	Volumetric from IS[11]	Each 10 year period starting 10 years before the period of extended operation[12]

Table Notes – Tank Inspection Recommendations

1. When one-time internal inspections in accordance with these footnotes are used in lieu of periodic inspections, the one-time inspection must occur within the 5-year period before the start of the period of extended operation.
2. Alternative inspection methods may be used to inspect both surfaces (i.e., internal, external) or the opposite surface (e.g., inspecting the internal surfaces for loss of material from the external surface, inspecting for corrosion under external insulation from the internal surfaces of the tank) as long as the method has been demonstrated to be effective at detecting the aging effect requiring management (AERM) and a sufficient amount of the surface is inspected to ensure that localized aging effects are detected. For example, in some cases, subject to being demonstrated effective by the applicant, the low frequency electromagnetic technique (LFET) can be used to scan an entire surface of a tank. If followup ultrasonic examinations are conducted in any areas where the wall thickness is below nominal, an LFET inspection can effectively detect loss of material in the tank shell, roof, or bottom.
3. Nonwetted surfaces on the inside of a tank (e.g., roof, surfaces above the normal waterline) are inspected in the same manner as the wetted surfaces based on the material, environment, and AERM.
4. Visual inspections to identify degradation of the inside surfaces of tank shell, roof, and bottom should cover all the inside surfaces.
5. For tank configurations in which deleterious materials could accumulate on the tank bottom (e.g., sediment, silt), the internal inspections of the tank's bottom should include inspections of the side wall of the tank up to the top of the sludge-affected region.
6. At least 25 percent of the tank's internal surface is to be inspected using a method capable of precisely determining wall thickness. The inspection method should be capable of detecting both general and pitting corrosion and be demonstrated effective by the applicant.
7. At least one tank for each material and environment combination should be inspected. The tank inspection can be credited towards the sample population for one-time inspection in accordance with Section B.1.33.
8. For insulated tanks, the external inspections of tank surfaces that are insulated are conducted in accordance with the sampling recommendations in this aging management program (AMP). If the initial inspections meet the criteria described in the preceding "Alternatives to Removing Insulation" portion of this AMP, subsequent inspections may consist of external visual inspections of the jacketing in lieu of surface examinations. Tanks with tightly adhering insulation may use the "Alternatives to Removing Insulation" portion of this AMP for initial and all follow-on inspections.
9. A one-time inspection conducted in accordance with Section B.1.33 may be conducted in lieu of periodic instructions if an evaluation conducted before the PEO and during each 10-year period during the PEO demonstrates the absence of environmental impacts in the vicinity of the plant due

to: (a) the plant being located within approximately 5 miles of a saltwater coastline. or within 1/2 mile of a highway that is treated with salt in the wintertime or in areas in which the soil contains more than trace amounts of chlorides, (b) cooling towers where the water is treated with chlorine or chlorine compounds, and (c) chloride contamination from other agricultural or industrial sources. The evaluation should include soil sampling in the vicinity of the tank (because soil results indicate atmospheric fallout accumulating in the soil and potentially affecting tank surfaces) and sampling of residue on the top and sides of the tank to ensure that chlorides or other deleterious compounds are not present at sufficient levels to cause pitting corrosion, crevice corrosion, or cracking.

10. A minimum of either 25 sections of the tank's surface (e.g., 1-sguare-foot sections for tank surfaces. 1-linear-foot sections of weld length) or 20 percent of the tank's surface are examined. The sample inspection points are distributed in such a way that inspections occur in those areas most susceptible to degradation (e.g., areas where contaminants could collect, inlet and outlet nozzles, welds).
11. When volumetric examinations of the tank bottom cannot be conducted because the tank is coated. an exception should be stated, and the accompanying justification for not conducting inspections should include the considerations in footnote 13, below, or propose an alternative examination methodology.
12. A one-time inspection conducted in accordance with Section B.1.33 may be conducted in lieu of periodic inspections if an evaluation conducted before the PEO and during each 10-year period during the PEO demonstrates that the soil under the tank is not corrosive using actual soil samples that are analyzed for each individual parameter (e.g., resistivity, pH, redox potential, sulfides, sulfates, moisture) and overall soil corrosively. The evaluation should include soil sampling from underneath the tank.

This program will be implemented prior to the period of extended operation.

A.1.3 <u>Bolting Integrity Program</u>

The Bolting Integrity Program manages loss of preload, cracking, and loss of material for closure bolting for pressure-retaining components using preventive and inspection activities. Applicable industry standards and guidance documents such as NUREG-1339, EPRI NP-5769, and EPRI TR-104213 are used to delineate the program.

The Bolting Integrity Program will be enhanced as follows.

- Clarify prohibition on use of lubricants containing molybdenum disulfide (MoS_2) for bolting and specify that proper gasket compression will be visually verified following assembly. The scope of this enhancement will include applicable GGNS site procedures.

- Include consideration of the guidance applicable for pressure boundary bolting in NUREG-1339, EPRI NP-5769, and EPRI TR-104213.

- Include volumetric examination per ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1, for high-strength closure bolting regardless of code classification. High-strength closure bolting is that with an actual yield strength greater than or equal to 150 ksi.

- Include guidance from EPRI NP-5769 and EPRI TR-104213 for replacement of bolting.

Enhancements will be implemented prior to the period of extended operation.

A.1.4 Boraflex Monitoring Program

The Boraflex Monitoring Program manages the change in material properties (neutron-absorbing capacity) in the Boraflex material affixed to spent fuel racks using silica sampling, areal testing activities, and other monitoring activities. Inspection frequency and acceptance criteria are based on the GGNS response to NRC Generic Letter 96-04 and the GGNS technical specifications.

The Boraflex Monitoring Program will be enhanced as follows.

- GGNS will perform periodic surveillances of the Boraflex neutron absorbing material in the spent fuel pool at least once every 5 years using Boron-10 Areal Density Gage for Evaluating Racks (BADGER) testing.

  RACKLIFE analysis, or an equivalent methodolgy, will continue to be performed each cycle. This analysis will include a comparison of the RACKLIFE predicted silica to the plant measured silica. This comparison will determine if adjustments to the RACKLIFE loss coefficient are merited. The analysis will include projections to the next planned RACKLIFE analysis date to ensure current Region I storage locations will not need to be reclassified as Region II storage locations in the analysis interval.

Enhancements will be implemented prior to the period of extended operation.

A.1.5 Buried Piping and Tanks Inspection Program

The Buried Piping and Tanks Inspection Program manages loss of material for the external surfaces of buried and underground piping and tanks composed of any material through preventive, mitigative, and inspection activities. Preventive and mitigative actions include selectin of component materials, external coatings for corrosion control, backfill quality control and the application of cathodic protection. Cathodic protection is used for additional protection of buried piping and tanks. The cathodic protection system is monitored and trended annually in accordance with NACE standards SP-0169 and RP-0285. Soil testing will be performed at two locations near the stainless steel condensate storage system piping that is subject to aging management review. Measured parameters will include soil resistivity, bacteria, pH, moisture, chlorides and redox potential. If the soil is determined to be corrosive then the number of inspections will be increased from one to two prior to and during the period of extended operation. Inspection activities include non-destructive evaluation of pipe or tank wall thickness, and visual inspection of the exterior, as permitted by opportunistic or directed excavations.

This program will be implemented prior to the period of extended operation.

A.1.6 BWR CRD Return Line Nozzle Program

The BWR Control Rod Drive (CRD) Return Line Nozzle Program manages cracking on the intended function of the control rod drive return line nozzle using preventive, mitigative, and inservice inspection activities in accordance with GGNS commitments to Generic Letter 80-095 to implement the recommendations in NUREG-0619.

The BWR CRD Return Line Nozzle Program will be enhanced to include inspection of the CRD return line nozzle inconel end cap to carbon steel safe end dissimilar metal weld once prior to the period of extended operation and every 10 years thereafter.

Enhancements will be implemented prior to the period of extended operation.

A.1.7 BWR Feedwater Nozzle Program

The BWR Feedwater Nozzle Program manages cracking of the BWR feedwater nozzles using inspection activities. This program augments the examinations specified in the ASME Code, Section XI, with the recommendation of General Electric (GE) NE-523-A71-0594 Revision 1 to perform periodic inspection of critical regions of the BWR feedwater nozzles.

A.1.8 BWR Penetrations Program

The BWR Penetrations Program manages cracking of BWR vessel penetrations using inspection and flaw evaluation activities. Applicable industry standards and staff-approved BWRVIP documents including BWRVIP-27-A, BWRVIP-47-A, and BWRVIP-49-A are used to delineate the program.

The BWR Penetrations Program will be enhanced as follows.

- Site procedures which implement the guidelines of BWRVIP-47-A will be clarified to indicate that the guidelines of BWRVIP-47-A apply without exceptions.

Enhancements will be implemented prior to the period of extended operation.

A.1.9 BWR Stress Corrosion Cracking Program

The BWR Stress Corrosion Cracking Program manages cracking of relevant piping and piping welds regardless of code classification using preventive measures, inspection, and flaw evaluation. Staff-approved BWRVIP documents and the GGNS response to NUREG-0313 Revision 2 and NRC Generic Letter 88-01 and its Supplement 1 are used to delineate the program. GGNS selects Catergory A welds for inspection in accordance with a risk-informed inservice inspection method. In the event a risk-informed inservice inspection method is not approved for use at GGNS, the inspection scope and schedule for Catergory A welds will be in accordance with BWRVIP-75-A.

A.1.10 BWR Vessel ID Attachment Welds Program

The BWR Vessel ID Attachment Welds Program manages cracking in structural welds for BWR reactor vessel internal integral attachments using inspection and flaw evaluation in conformance with the guidelines of BWRVIP-48-A.

A.1.11 BWR Vessel Internals Program

The BWR Vessel Internals Program manages cracking, loss of material, and reduction of fracture toughness for BWR vessel internal components using inspection and flaw evaluation. This program also provides (1) determination of the susceptibility of cast austenitic stainless steel components, (2) accounting for the synergistic effect of thermal aging and neutron irradiation, and (3) implementation of a supplemental examination program, as necessary. Applicable industry standards and staff-approved BWRVIP documents are used to delineate the program.

The BWRVIP is an industry program providing for implementation of guidelines for inspection and evaluation, repair, water chemistry, and other activities supporting assurance of continued integrity of BWR primary components. As indicated in the July 29, 1997 letter from Brian W. Sheron (NRC) to Carl Terry (BWRVIP Chairman), the U.S. BWR fleet, including GGNS, is commited to comply with BWRVIP guidelines.

Steam dryer inspection and evaluation are based on BWRVIP-139-A. Following the second refueling outage after implementation of the extended power uprate, the BWRVIP-139-A recommendations will be supplemented by any additional inspection requirements determined for the long-term steam dryer inspection plan submitted for NRC review and approval in accordance with License Condition 46 part (g).

The BWR Vessel Internals Program will be enhanced as follows.

- The susceptibility to neutron or thermal embrittlement for reactor vessel internal components composed of CASS, X-750 alloy, precipitation-hardened (PH) martensitic stainless steel (e.g., 15-5 and 17-4 PH steel), and martensitic stainless steel (e.g., 403, 410, 431 steel) will be evaluated. This evaluation will include a plant-specific identification of the reactor vessel internals components made of these materials.

- Portions of the susceptible components determined to be limiting from the standpoint of thermal aging susceptibility, neutron fluence, and cracking susceptibility (i.e., applied stress, operating temperature, and environmental conditions) will be inspected, using an inspection technique capable of detecting the critical flaw size with adequate margin. The critical flaw size will be determined based on the service loading condition and service-degraded material properties. The initial inspection will be performed either prior to or within 5 years after entering the period of extended operation. If cracking is detected after the initial inspection, the frequency of re-inspection will be justified based on fracture toughness

- properties appropriate for the condition of the component. The sample size for the initial inspection of susceptible components will be 100% of the accessible component population, excluding components that may be in compression during normal operations.

Enhancements will be implemented prior to the period of extended operation.

A.1.12 Compressed Air Monitoring Program

The Compressed Air Monitoring Program manages loss of material in compressed air systems by monitoring air samples for moisture and contaminants and by inspecting internal surfaces within compressed air systems. Inspection frequency and acceptance criteria are based on the GGNS response to NRC Generic Letter 88-14 and applicable industry standards and guidance documents.

The Compressed Air Monitoring Program will be enhanced as follows.

- Apply a consideration of the guidance of ASME OM-S/G-1998, Part 17; American National Standards Institute (ANSI)/ISA-S7.0.01-1996; EPRI NP-7079; and EPRI TR-108147 to the limits specified for air system contaminants.

- Include periodic and opportunistic inspections of accessible internal surfaces of piping, compressors, dryers, aftercoolers, and filters and to apply consideration of the guidance of ASME OM-S/G-1998, Part 17 for inspection frequency and inspection methods of these components in the following compressed air systems.
  - Automatic Depressurization System (ADS) air
  - Division 1 Diesel Generator Starting Air (D1DGSA)
  - Division 2 Diesel Generator Starting Air (D2DGSA)
  - Division 3 Diesel Generator Starting Air (D3DGSA), also known as the HPCS Diesel Generator
  - Instrument Air (IA) - system P53

Enhancements will be implemented prior to the period of extended operation.

A.1.13 Containment Inservice Inspection – IWE Program

The Containment Inservice Inspection - IWE Program is a general visual examination that assesses the condition of the containment steel liner and detects evidence of degradation that may affect structural integrity or leak tightness. This examination satisfies the requirements of the ASME Boiler and Pressure Vessel Code (to include the 1998 edition with 1999 and 2000 addenda, 2001 edition with 2003 addenda, and the 2004 Code Edition), Section XI, Subsection IWE Examination Category E-A.

The program is augmented by existing plant procedures to ensure that the selection of bolting material installation torque or tension and the use of lubricants and sealants is appropriate for the intended purpose. These procedures reference guidance contained in EPRI TR-104213, NUREG-

1339 and EPRI NP-5769 to ensure proper specification of bolting material, lubricant, and installation torque.

A.1.14 Containment Inservice Inspection – IWL Program

The Containment Inservice Inspection – IWL Program is a general visual examinations that assesses the overall condition of the containment concrete and detects evidence of degradation that may affect structural integrity or leak tightness. These examinations are used to meet the examination requirements of the ASME Boiler and Pressure Vessel Code (1998 Edition with the 2000 Addenda, 2001 Edition through the 2003 Addenda, and 2004 Edition) Section XI, Subsection IWL Examination Category L-A, Item Numbers L1.11, L1.12, and L2.30. In accordance with GGNS specific relief requests, these examinations are also used as an alternative to the examinations specified in the 1992 edition with 1992 addenda for IWL Examination Category L-A.

A.1.15 Containment Leak Rate Program

The Containment Leak Rate Program provides for detection of loss of material, cracking, and loss of function in various systems penetrating containment. The program also provides for detection of age-related degradation in material properties of gaskets, O-rings, and packing materials for the primary containment pressure boundary access points.

Containment leakage rate tests (LRT) are performed to assure that leakage through the containment and systems and components penetrating primary containment does not exceed allowable leakage limits specified in the plant technical specifications. Types A, B and C leakage rate testing will be implemented in accordance with the criteria set forth in RG 1.163, NEI 94-01, Revision 3-A, adopting, in part, the testing criteria of ANSI/ANS-56.8-2002. An integrated leak rate test (Type A) is performed during a period of reactor shutdown. Performance of the integrated leak rate test per 10 CFR Part 50, Appendix J demonstrates the leak-tightness and structural integrity of the containment. Local leak rate tests (Type B and C) are performed on isolation valves and containment access penetrations. Test frequencies for Types A, B and C leakage rate testing comply with the requirements of 10 CFR Part 50, Appendix J, Option B, based upon the criteria in NEI 94-01, Revision 3-A.

A.1.16 Diesel Fuel Monitoring Program

The Diesel Fuel Monitoring Program manages loss of material and fouling in piping and components exposed to an environment of diesel fuel oil by verifying the quality of fuel oil and controlling fuel oil contamination as well as periodic draining, cleaning, and inspection of tanks. Applicable industry standards and guidance documents are used to delineate the program. Acceptance criteria for fuel oil quality parameters are specified in the GGNS technical specifications.

The One-Time Inspection Program describes inspections planned to verify that the Diesel Fuel Monitoring Program has been effective at managing aging effects.

The Diesel Fuel Monitoring Program will be enhanced as follows.

- Include a ten-year periodic cleaning and internal inspection of the fire water pump diesel fuel oil tanks (SP64A002A/B), the diesel fuel oil day tanks for Divisions I, II, III, and the diesel fuel oil drip tanks for Divisions I, II. These cleanings and internal inspections will be performed at least once during the 10-year period prior to the period of extended operation and at succeeding 10-year intervals. If visual inspection is not possible, a volumetric inspection will be performed.

- Include a volumetric examination of affected areas of the diesel fuel tanks if evidence of degradation is observed during visual inspection. The scope of this enhancement includes the diesel fuel oil day tanks (Divisions I, II, III), the diesel fuel oil storage tanks (Divisions I, II, III), the diesel fuel oil drip tanks (Divisions I, II), and the diesel fire pump fuel oil storage tanks, and is applicable to the inspections performed during the 10-year period prior to the period of extended operation and at succeeding 10-year intervals.

Enhancements will be implemented prior to the period of extended operation.

A.1.17 Environmental Qualification (EQ) of Electric Components Program

The Environmental Qualification (EQ) of Electric Components Program manages the effects of thermal, radiation, and cyclic aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. As required by 10 CFR 50.49, EQ components are refurbished, replaced, or their qualification is extended prior to reaching the aging limits established in the evaluation. Reanalysis of an aging evaluation addresses attributes of analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions. Some aging evaluations for EQ components are time-limited aging analyses (TLAAs) for license renewal.

A.1.18 External Surfaces Monitoring Program

The External Surfaces Monitoring Program manages aging effects through visual inspection of external surfaces for evidence of loss of material, cracking and change in material properties. Physical manipulation to detect hardening or loss of strength for elastomers and polymers is also used.

The External Surfaces Monitoring Program will be enhanced as follows.

- Include instructions for monitoring aging effects for flexible polymeric components through manual or physical manipulation of the material, with a sample size for manipulation of at least 10 percent of available surface area.

- Clearly identify underground components within the scope of this program in program documents. Underground components are those for which access is physically restricted.

- Provide instructions for inspecting all underground components within the scope of this program during each 5-year period, beginning 10 years prior to the entry into the period of extended operation.

- Revise External Surfaces Monitoring Program procedures to specify the following for insulated components.

  - Periodic representative inspections will be conducted during each 10-year period during the PEO.

  - For a representative sample of insulated indoor components exposed to condensation (because the component is operated below the dew point), insulation will be removed for visual inspection of the component surface. Inspections will include a minimum of 20 percent of the in-scope piping length for each material type (e.g., steel, stainless steel, copper alloy, aluminum), or for components with a configuration which does not conform to a 1-foot axial length determination (e.g., valve, accumulator), 20 percent of the surface area. Alternatively, insulation will be removed and a minimum of 25 inspections will be performed that can be a combination of 1-foot axial length sections and individual components for each material type.

  - Inspection locations will be based on the likelihood of corrosion under insulation (CUI). For example, CUI is more likely for components experiencing alternate wetting and drying in environments where trace contaminants could be present and for components that operate for longer periods of time below the dew point. Subsequent inspections can be limited to an examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation, if the following conditions are verified in the initial inspection.

    - No loss of material due to general, pitting or crevice corrosion, beyond that which could have been present during initial construction, and

    - No evidence of cracking.

    If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation of there is evidence of water intrusion through the insulation (e.g., water seepage through insulation seams/joints), periodic inspections under the insulation will continue as described above.

  - Removal of tightly adhering insulation that is impermeable to moisture is not required unless there is evidence there is evidence of damage to the moisture barrier. Tightly adhering insulation is considered a separate population from the remainder of insulation installed on in-scope components. The entire population of in-scope accessible piping component surfaces that have tightly adhering insulation will be visually inspected for damage to the moisture barrier at the same frequency as

- inspections of other types of insulation. These inspections will not be credited towards the inspection quantities for other types of insulation.

Enhancements will be implemented prior to the period of extended operation.

A.1.19 <u>Fatigue Monitoring Program</u>

The Fatigue Monitoring Program ensures that fatigue usage remains within allowable limits by (a) tracking the number of critical thermal and pressure transients for selected components, (b) verifying that the severity of monitored transients are bounded by the design transient definitions for which they are classified, and (c) assessing the impact of the reactor coolant environment on a set of sample critical components.

Transient cycle logging and fatigue monitoring software are used together to ensure cumulative usage factors do not exceed design limits. The Fatigue Monitoring Program utilizes both fatigue monitoring software and manual cycle counting techniques. In addition to providing cycle counting information, the fatigue monitoring software determines cycle-based fatigue and stress-based fatigue based on actual transients incurred. Cycle-based fatigue monitoring utilizes cycle counts that have occurred and design basis fatigue calculations to calculate usage for a specific location and make projections of future fatigue usage. Stress-based fatigue monitoring calculates stress and fatigue based on actual stress loadings. The combination of cycle counting, cycle-based fatigue monitoring and stress-based fatigue monitoring ensures that cumulative usage factors will be maintained within allowable limits.

The Fatigue Monitoring Program will be enhanced as follows.

- A review of the GGNS high energy line break analyses and the corresponding tracking of associated cumulative usage factors will be performed to ensure that the GGNS program adequately manages fatigue usage for these locations.

- Fatigue usage calculations that consider the effects of the reactor water environment will be developed for a set of sample reactor coolant system components. This sample set will include the locations identified in NUREG/CR-6260 and additional plant-specific component locations in the reactor coolant pressure boundary if they are found to be more limiting than those considered in NUREG/CR-6260. F_{en} factors will be determined using the formulae sets listed in Section A.2.2.3. **If** necessary following this analysis, revised cycle limits will be incorporated into the Fatigue Monitoring Program documentation.

- Program guidance documents will be revised to provide updates of the fatigue usage calculations on an as-needed basis if an allowable cycle limit is approached, or in a case where a transient definition has been changed, unanticipated new thermal events are discovered, or the geometry of components has been modified. The program revision will include providing for the consideration of the recirculation pump fatigue analysis exemption validity if cycles that were input into the exemption evaluation exceed their limits.

Enhancements will be implemented at least two years prior to entering the period of extended operation.

A.1.20 Fire Protection Program

The Fire Protection Program manages cracking, loss of material, and change in material properties through visual inspection of components and structures with a fire barrier intended function. It also manages loss of material for the CO_2 and clean agent (a term used to encompass Halon 1301, Novec 1230, or similar fire suppression agent) fire suppression systems through periodic visual inspection and testing. The program includes functional tests of fire rated doors. The Fire Protection Program includes monitoring the level and pressure of the CO_2 tank on a daily basis during the period of extended operation.

The Fire Protection Program will be enhanced as follows.

- Require visual inspections of the clean agent/CO_2 fire suppression system at least once every fuel cycle to examine for signs of corrosion.

- Require visual inspections of fire damper framing at least once every fuel cycle to check for signs of degradation.

- Require visual inspections of concrete curbs, manways, hatches, manhole covers, hatch covers, and roof slabs at least once every fuel cycle to confirm that aging effects are not occurring.

- Require an external visual inspection of the CO_2 tank at least once every fuel cycle to examine for signs of corrosion.

Enhancements will be implemented prior to the period of extended operation.

A.1.21 Fire Water System Program

The Fire Water System Program manages loss of material, loss of coating integrity, and fouling for components in fire protection systems using preventive, inspection, and monitoring activities, including periodic full-flow flush tests, system performance testing, and testing or replacement of sprinkler heads. Applicable industry standards and guidance documents, including NFPA codes, are used to delineate the program. The program includes acceptance criteria for the water-based fire protection system to maintain required pressure, and acceptance criteria will be enhanced to verify no unacceptable degradation. Corrective action is initiated upon loss of system operating pressure, which is monitored continuously.

The Fire Water System Program will be enhanced as follows.

- Revise Fire Water System Program procedures to ensure sprinkler heads are tested or replaced in accordance with NFPA-25 (2011 Edition), Section 5.3.1.

- Revise Fire Water System Program procedures to specify replacing any sprinkler that shows signs of leakage or corrosion.

- Revise Fire Water System Program procedures to perform a flow blockage evaluation if during main drain testing, the flowing pressure drops more than 10 percent from the flowing pressure observed during the original acceptance test or other previously performed tests at the same location.

- Revise Fire Water System Program procedures to ensure there is no flow blockage by visually inspecting the charcoal filter deluge fire water distribution piping when the charcoal is replaced.

- Revise Fire Water System Program procedures to perform air flow testing to ensure there are no obstructions downstream of the deluge valves for control room fresh air, auxillary building standby gas, containment cooling system, and containment vent charcoal filter units each refueling cycle.

- Revise Fire Water System Program procedures to include periodic internal inspections and documentation of any excessive accumulation of corrosion products or appreciable localized corrosion (e.g., pitting) beyond a normal oxide layer in the corrective action program and that follow-up volumetric wall thickness examination will be performed as part of the corrective action.

- Revise Fire Water System Program procedures to require internal inspections at the end of one fire main and the end of one branch line on two of the wet pipe systems in the auxiliary building, two of the wet pipe systems in the control building, and one wet pipe system in the fire pump house every five years. During each five-year internal inspection period, inspect different wet pipe sprinklers such that internal inspections are performed on all of the wet pipe sprinkler systems in the auxiliary and control buildings every 15 years and in the fire pump house every 10 years. In the event internal obstructions are identified in a building wet pipe system, expand the number of inspections to include all of the wet pipe sprinkler systems in that building.

- Revise Fire Water System Program procedures to periodically open a flushing connection at the end of a main and remove a component such as a sprinkler toward the end of one branch line for piping associated with preaction and dry pipe systems to perform a visual inspection in accordance with NFPA 25 (2011 Edition) Section 14.2.1.

- Revise Fire Water System Program procedures to inspect the normally dry fire suppression piping and piping components with a 10 CFR 54.4(a)(3) intended function that may be wetted to ensure that the piping does not collect water. In the event areas are identified that collect water, perform the following augmented tests and inspections to ensure that flow blockage has not occurred.

1. In each 5-year interval beginning with the 5-year period before the period of extended operation, perform either (a) a flow test or flush sufficient to detect potential flow blockage, or (b) visual inspections on 100 percent of the internal surface of piping segments that allow water to collect.

2. In each 5-year interval during the period of extended operation, perform volumetric wall thickness inspections on 20 percent of the length of piping segments that allow water to collect. Data points are obtained to the extent that potential degraded condtions can be identified (e.g., general corrosion, MIC). The 20 percent of piping inspected in each 5-year interval should be in different locations than piping inspected in previous intervals.

If the results of a 100 percent interval visual inspection are acceptable and the segment is not subsequently wetted, no futher augmented tests or inspections are necessary.

- Revise Fire Water System Program procedures to include inspecting sprinklers in the overhead from the floor for signs of corrosion.
- Revise Fire Water System Program procedure to include periodic inspection of hose reels for degradation.
- Revise Fire Water System Program procedures to replace sprinklers that the tested sprinkler represents, if the tested sprinkler fails to meet the test acceptance criteria.
- Revise Fire Water System Program procedures to ensure the hydrant valve is opened fully and ensure the hydrant flows for not less than one minute during flow testing.
- Revise Fire Water System Program procedures for inspecting the interior of the fire water tanks to include the following.

  1. A Review of at least two previous coating inspection results is performed prior to conducting a coating inspection.

  2. The coating inspection report will include a list of locations identified with coating degradaton including, where possible, photograghs indexed to inspection location, and a prioritization of the repair areas into areas that must be repaired before returning the system to service and areas where coating repair can be postponed to a subsequent inspection or repair opportunity.

- Revise Fire Water System Program procedures for inspecting the interior of the fire water tanks at the frequency specified by NFPA 25 Section 9.2.6 to include the following.

  1. Testing for possible voids beneath the tank.

2. Inspection of the vortex breaker.

3. Coating inspections and documentation, and review of inspection results are performed by qualified personnel.

   - Individuals performing coating inspections are certified to ANSI N45.2.6, “Qualifications of Inspection, Examination, and Testing Personnel for Nuclear Power Plants.”

   - A nuclear coatings specialist qualified in accordance with ASTM D 7108-05, “Standard Guide for Establishing Qualifications for a Nuclear Coatings Specialist,” will evaluate inspection findings and prepare post-inspection reports.

- Revise Fire Water System Program procedures to determine the extent of coating defects on the interior of the fire water tanks by using one or more of the following methods when conditions such as cracking, peeling, blistering, delamination, rust or flaking are identified during visual examination.

  1. Adhesion testing endorsed by Regulatory Guide 1.54.

  2. Dry film thickness measurements at random locations to determine overall coating thickness as specificed in NFPA 25 (2011 Edition) Section 9.2.7 Item (2).

  3. Nondestructive ultrasonic readings to evaluate the wall thickness where there is evidence of pitting or corrosion as specified in NFPA 25 (2011 Edition) Section 9.2.7 Item (3).

  4. Spot wet-sponge tests to detect pinholes, cracks, or other compromises in the coating as specified in NFPA 25 (2011 Edition) Section 9.2.7 Item (4).

  5. Test the tank bottom for metal loss or rust on the underside by use of ultrasonic testing where there is evidence of pitting or corrosion as specified in NFPA 25 (2011 Edition) Section 9.2.7 Item (5).

- Revise Fire Water System Program procedures to determine the extent of coating defects on the interior of the fire water tanks by using one or more of the following methods when conditions such as cracking, peeling, blistering, delamination, rust or flaking are identified during visual examination in accordance with NFPA 25 (2011), Section 9.2.6.4.

  1. Lightly tapping and scraping the coating to determine the coating integrity.
  2. Dry film thickness measurements at random locations to determine overall thickness of the coating.
  3. Wet-sponge testing or dry film testing to identify holidays in the coating.

4. Adhesion testing in accordance with ASTM D3359, ASTM D4541, or equivalent testing endorsed by RG 1.54 at a minimum of three locations.
5. Ultrasonic testing where there is evidence of pitting or corrosion to determine if the tank thickness meets the minimum thickness criteria.

- Revise the Fire Water System Program procedures to ensure a fire water tank is not returned to service after identifying interior coating blistering, delamination or peeling unless there are only a few small intact blisters surrounded by coating bonded to the substrate as determined by a qualified coating specialist, or the following actions are performed.
  1. Any blistering in excess of a few small intact blisters, or blistering not completely surrounded by coating bonded to the substrate is removed,
  2. Any delaminated or peeled coating is removed,
  3. The exposed underlying coating is verified to be securely bonded to the substrate as determined by an adhesion test endorsed by RG 1.54 at a minimum of three locations,
  4. The outermost coating is feathered and the remaining outermost coating is determined to be securely bonded to the coating below via an adhesion test endorsed by Reg. Guide 1.54 at a minimum of three locations adjacent to the defective area,
  5. Ultrasonic testing is performed where there is evidence of pitting or corrosion to ensure the tank meets minimum wall thickness requirements,
  6. An evaluation is performed to ensure downstream flow blockage is not a concern, and
  7. A follow-up inspection is scheduled to be performed within two years and every two years after that until the coating is repaired, replaced, or removed.
- Revise the Fire Water System Program procedures to include the following acceptance criteria for loss of coating integrity.
  1. Indications of peeling and delamination are not acceptable.
  2. Blisters are evaluated by a coating specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 including staff limitations associated with use of a particular standard. Blisters should be limited to a few intact small blisters that are completely surrounded by sound coating/lining bonded to the substrate. Blister size and frequency should not be increasing between inspections (e.g., reference ASTM D714-02, "Standard Test Method for Evaluating Degree of Blistering of Paints").
  3. Indications such as cracking, flaking, and rusting are to be evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 including staff limitations associated with the use of a particular standard.
  4. Minor cracking and spalling of cementitious coatings/linings is acceptable provided there is no evidence that the coating/lining is debonding from the base material.

5. As applicable, wall thickness measurements, projected to the next inspection, meet design minimum wall requirements.

6. Adhesion testing results, when conducted, meet or exceed the degree of adhesion recommended in plant-specific design requirements specific to the coating/lining and substrate.

- Revise Fire Water System Program procedures to include a visual inspection of a representative number of locations on the interior surface of below grade fire protection piping at a frequency of at least once every 10 years during the period of extended operation. A representative number is 20% of the population (defined as locations having the same material, environment, and aging effect combination) with a maximum of 25 locations.

- Revise Fire Water System Program procedures to inspect the strainers upstream of the deluge valves every three years.

- Revise Fire Water System Program procedures for flow testing, main drain testing, or internal inspection to specify an acceptance criterion of no debris observed (i.e., no corrosion products that are sufficient to obstruct flow or cause downstream components to become clogged.)

- Revise Fire Water System Program procedures to require an obstruction evaluation if any signs of abnormal corrosion or blockage are identified during flow testing, main drain testing, or internal inspection. Any signs of corrosion or blockage should be removed, its source determined and corrected, and the condition entered into the Corrective Action Program. Where corrosion or blockage is found, the obstruction evaluation should consider system valves, risers, cross mains and branch lines, and the performance of a complete flushing program by qualified personnel.

- Revise Fire Water System Program procedures to require an obstruction evaluation in the event there is frequent false tripping of the dry pipe fire suppression system associated with the auxiliary building railroad access.

Enhancements will be implemented prior to the period of extended operation.

A.1.22 Flow-Accelerated Corrosion Program

The Flow-Accelerated Corrosion (FAC) Program manages loss of material due to wall thinning for piping and components by conducting appropriate analysis and baseline inspections, determining the extent of thinning, performing follow-up inspections, and taking corrective actions as necessary. The FAC program also manages the effects of aging due to other wall-thinning mechanisms that may be identified through industry or plant-specific operating experience. The program follows guidelines published by EPRI in NSAC-202L.

The FAC Program will be enhanced as follows.

- Revise program documentation to specify that downstream components are monitored closely to mitigate any increased wear when susceptible upstream components are replaced with resistant materials, such as high chromium material.
- Revise program documentation to specify that components subject to wall-thinning mechanisms other than FAC, which are replaced with alternate materials (e.g., replacing a carbon steel pipe with stainless steel) shall continue to be periodically monitored at a frequency commensurate with their post-replacement wear rates and operating times.

These enhancements will be implemented prior to the period of extended operation.

A.1.23 Inservice Inspection Program

The Inservice Inspection Program manages aging effects for ASME Class 1, 2, and 3 pressure-retaining components including welds, pump casings, valve bodies, integral attachments, and pressure-retaining bolting using volumetric, surface, or visual examination as specified in ASME Section XI code. Every ten years this program is updated to the latest ASME Section XI code edition and addendum approved by the NRC in 10 CFR 50.55a.

A.1.24 Inservice Inspection – IWF Program

The Inservice Inspection – IWF Program manages aging effects for ASME Class 1, 2, 3 piping and component supports. The scope of inspection for component supports is based on sampling of piping supports and 100 percent of component supports other than piping as specified in Table IWF-2500-1.

The Inservice Inspection – IWF Program will be enhanced as follows.

- Address inspections of accessible sliding surfaces.
- Clarify that parameters monitored or inspected will include corrosion; deformation; misalignment of supports; missing, detached, or loosened support items; improper clearances of guides and stops; and improper hot or cold settings of spring supports and constant load supports. Accessible areas of sliding surfaces will be monitored for debris, dirt, or indications of excessive loss of material due to wear that could prevent or restrict sliding as intended in the design basis of the support. Structural bolts will be monitored for corrosion and loss of integrity of bolted connections due to self-loosening and material conditions that can affect structural integrity. High-strength structural bolting (actual measured yield strength greater than or equal to 150 ksi or 1,034 MPa in sizes greater than 1 inch nominal diameter) susceptible to stress corrosion cracking (SCC) will be monitored for SCC.

- Clarify that detection of aging effects will include:
  a) Monitoring structural bolting (ASTM A-325, ASTM F1852, and ASTM A490 bolts) and anchor bolts for loss of material, loose or missing nuts, loss of pre-load and cracking of concrete around the anchor bolts.
  b) Volumetric examination comparable to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1 for high strength structural bolting to detect cracking in addition to the VT-3 examination. This volumetric examination may be waived with adequate plant-specific justification.
  c) Identification of all component supports that contain high strength bolting (actual measured yield greater than or equal to 150 ksi) in sizes greater than 1 inch nominal diameter. The extent of examination for support types that contain high-strength bolting will be as specified in ASME Code Section XI, Table IWF-2500-1. GGNS will examine high strength structural bolting on the frequency specified in ASME Code Section XI, Table IWF-2500-1.

- Include the following as unacceptable conditions.
  a) Loss of material due to corrosion or wear, which reduces the load bearing capacity of the component support.
  b) Debris, dirt, or excessive wear that could prevent or restrict sliding of the sliding surfaces as intended in the design basis of the support.
  c) Cracked or sheared bolts, including high strength bolts, and anchors.

- When a component support is found with minor age-related degradation, but still is evaluated as “acceptable for continued service” as defined in IWF-3400, the program owner may choose to repair the degraded component and substitute a randomly selected component that is more representative of the general population for it in subsequent inspections.

- Clarify that preventive action will include:

  Incorporate into plant procedures recommendations delineated in NUREG-1339, and Electric Power Research Institute (EPRI) NP-5769 and TR-104213 for high-strength structural bolting. These recommendations address proper selection of bolting material, proper installation torque or tension, and the use of appropriate lubricants and sealants.

Enhancements will be implemented prior to the period of extended operation.

A.1.25 Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program

The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program consists of periodic inspections and preventive maintenance to manage loss of material for cranes and hoists, based on applicable industry standards and guidance documents. The

activities rely on visual examinations and functional testing to ensure that cranes and hoists are capable of sustaining their rated loads, thus ensuring their intended function is maintained during the period of extended operation.

The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program will be enhanced as follows.

- The scope will include monitoring of rails in the rail system for the aging effect wear and structural connections/bolting for loose or missing bolts, nuts, pins or rivets. Additionally, include visual inspection of structural components and structural bolts for loss of material due to various mechanisms and structural bolting for loss of preload due to self-loosening.

- Revise acceptance criteria to state that any significant loss of material for structural components and structural bolts and significant wear of rails in the rail system is evaluated according to ASME B30.2 or other applicable industry standard in the ASME B30 series.

Enhancements will be implemented prior to the period of extended operation.

A.1.26 Internal Surfaces in Miscellaneous Piping and Ducting Components Program

The Internal Surfaces in Miscellaneous Piping and Ducting Components Program manages the effects of aging using opportunistic visual inspections of the internal surfaces of metallic piping, piping components, ducting, elastomeric components, and other components during periodic surveillances or maintenance activities when the surfaces are accessible for visual inspection. To ensure a representative number of components are inspected, in each 10-year period during the period of extended operation (PEO), an assessment will be made of the opportunistic inspections completed during that period for each material-environment-aging effect combination within the scope of this program. Directed inspections will be conducted to ensure that an inspection sample size of 20 percent, with a maximum sample size of 25 inspecitons, is completed for each material-environment-aging effect combination during the 10-year period under review. Where practical, inspections shall be conducted at locations that are most susceptible to the effects of aging because of time in service, severity of operating conditions (e.g., low or stagnant flow), and lowest design margin. An inspection conducted of a material in a more severe environment may be credited as an inspection of the same material in a less severe environment.

The program inspections ensure that environmental conditions are not causing material degradation that could result in a loss of the component's intended function. For metallic components visual inspection will be used to detect loss of material and fouling. For elastomeric and plastic components, visual inspections will be used to detect cracking and change in material properties. Visual examinations of elastomeric components are accompanied by physical manipulation or pressurization (i.e., the component is sufficiently pressurized to expand the surface of the material in such a way that cracks or crazing are evident) such that changes in material properties are readily observable. The sample area subject to manipulation of flexible elastomeric components is at least 10 percent of the available surface area. The program manages the effects of aging for

piping and components exposed to environments of air-indoor, air-outdoor, condensation, exhaust gas, lube oil, raw water, waste water, and treated water.

This program will be implemented prior to the period of extended operation.

A.1.27 Masonry Wall Program

The Masonry Wall Program manages aging effects for each masonry wall within the scope of license renewal. The program includes visual inspection of masonry walls including 10 CFR 50.48-required masonry walls, radiation-shielding masonry walls, and masonry walls with the potential to affect safety-related components. Structural steel components of masonry walls are managed by the Structures Monitoring Program. Masonry walls are visually examined at a frequency selected to ensure there is no loss of intended function between inspections.

The Masonry Wall Program will be enhanced as follows.

- Monitor gaps between the supports and masonry walls that could potentially affect wall qualification.
- Require masonry walls to be inspected every five years.

Enhancements will be implemented prior to the period of extended operation.

A.1.28 Non-EQ Cable Connections Program

The Non-EQ Cable Connections Program is a one-time inspection program that provides reasonable assurance that the intended functions of the metallic parts of electrical cable connections are maintained consistent with the current licensing basis through the period of extended operation. Cable connections included are those connections susceptible to age-related degradation resulting in increased resistance of connection due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation that are not subject to the environmental qualification requirements of 10 CFR 50.49.

This program provides for one-time quantitative inspections that will be completed prior to the period of extended operation on a sample of connections. The factors considered for sample selection will be application (medium and low voltage, defined as < 35 kV), circuit loading (high loading), connection type, and location (high temperature, high humidity, vibration, etc.). The representative sample size will be based on twenty percent of the connection population with a maximum sample of 25.

Inspection methods may include thermography, contact resistance testing, or other appropriate guantitative test methods without removing the connection insulation, such as heat shrink tape, sleeving, insulating boots, etc., based on plant configuration and industrv guidance.

This program will be completed prior to the period of extended operation.

A.1.29 Non-EQ Inaccessible Power Cables (400 V to 35 kV) Program

The Non-EQ Inaccessible Power Cables (400 V to 35kV) Program manages the aging effects on the inaccessible power (400 V to 35kV) cable systems. The program includes periodic actions to prevent inaccessible cables from being exposed to significant moisture. In this program, inaccessible power (400 V to 35kV) cables exposed to significant moisture are tested at least once every six years to provide an indication of the condition of the cable insulation properties. Test frequencies are adjusted based on test results and operating experience. The specific type of test performed is a proven test for detecting deterioration of the cable insulation. The program includes periodic inspections for water accumulation in manholes at least once every year (annually). In addition to the periodic manhole inspections, manhole inspection for water after events such as heavy rain or flooding will be performed. Inspection frequency will be increased as necessary based on evaluation of inspection results.

The Non-EQ Inaccessible Power Cables (400 V to 35 kV) Program will be enhanced as follows.

- Include low-voltage (400 V to 2 kV) power cables.
- Condition-based inspections of manholes not automatically dewatered by a sump pump will be performed following periods of heavy rain or potentially high water table conditions, as indicated by river level.
- Clarify that the manhole inspections will include direct observation that cables are not wetted or submerged, that cables/splices and cable support structures are intact, and verification that dewatering/drainage systems (i.e., sump pumps) and associated alarms if applicable operate properly.

Enhancements will be implemented prior to the period of extended operation, and the first cable tests and manhole inspections will be completed prior to the period of extended operation.

A.1.30 Non-EQ Instrumentation Circuits Test Review Program

The Non-EQ Instrumentation Circuits Test Review Program manages the aging effects of the applicable cables in the neutron monitoring and process radiation monitoring systems or sub-systems. The program assures the intended functions of sensitive, high-voltage, low-signal cables exposed to adverse localized equipment environments caused by heat, radiation and moisture (i.e., neutron flux monitoring instrumentation and process radiation monitoring) can be maintained consistent with the current licensing basis through the period of extended operation. Most sensitive instrumentation circuit cables and connections are included in the instrumentation loop calibration at the normal calibration frequency, which provides sufficient indication of the need for corrective actions based on acceptance criteria related to instrumentation loop performance. The review of calibration results will be performed once every ten years, with the first review occurring before the period of extended operation.

For sensitive instrumentation circuit cables that are disconnected during instrument calibrations, testing using a proven method for detecting deterioration for the insulation (such as insulation resistance tests or time domain reflectometry) will occur at least once every ten years, with the first test occurring before the period of extended operation. Applicable industry standards and guidance documents are used to delineate the program.

This program will be implemented prior to the period of extended operation.

A.1.31 Non-EQ Insulated Cables and Connections Program

The Non-EQ Insulated Cables and Connections Program assures the intended functions of insulated cables and connections exposed to adverse localized environments caused by heat, radiation and moisture can be maintained consistent with the current licensing basis through the period of extended operation. An adverse localized environment is a condition in a limited plant area that is significantly more severe than the plant design environment for the cable or connection insulation materials.

A representative sample consisting of accessible insulated cables and connections within the scope of license renewal installed in an adverse localized environment will be visually inspected for cable and connection jacket surface anomalies such as embrittlement, discoloration, cracking, melting, swelling, or surface contamination. The program sample consists of all accessible cables and connections in localized adverse environments, and this program sample of accessible cables will represent, with reasonable assurance, all cables and connections in the adverse localized environment.

This program will visually inspect accessible cables in an adverse localized environment at least once every ten years, with the first inspection prior to the period of extended operation.

This program will be implemented prior to the period of extended operation.

A.1.32 Oil Analysis Program

The Oil Analysis Program ensures that loss of material, cracking, and fouling are not occurring by maintaining oil environments free of contaminants (primarily water and particulates). Testing activities include sampling and analysis of lubricating oil.

The One-Time Inspection Program utilizes inspections or non-destructive evaluations of representative samples to verify that the Oil Analysis Program has been effective at managing aging effects.

The Oil Analysis Program will be enhanced as follows.

- Include piping and components within the main generator system (N41) with an internal environment of lube oil.

- Provide a formalized analysis technique for particulate counting.

Enhancements will be implemented prior to the period of extended operation.

A.1.33 <u>One-Time Inspection Program</u>

The One-Time Inspection Program consists of a one-time inspection of selected components to accomplish one of the following:

- Verify the effectiveness of an AMP that is designed to prevent or minimize aging to the extent that it will not cause the loss of intended function during the period of extended operation.

- Confirm the insignificance of an aging effect for situations in which additional confirmation is appropriate.

Inspections that verify unacceptable degradation is not occurring will be used.

The sample size of components to be inspected will be based on an assessment of materials, environment, aging effects, and operating experience. Identification of inspection locations will be based on the potential for the aging effect to occur. Examination techniques will be established NDE methods with a demonstrated history of effectiveness in detecting the aging effect of concern, including visual, ultrasonic, and surface techniques. Acceptance criteria will be based on applicable ASME or other appropriate standards, design basis information, or vendor-specified requirements and recommendations. The need for follow-up examinations will be evaluated.

The program will include activities to verify effectiveness of aging management programs and activities to confirm the insignificance of aging effects as described below.

Diesel fuel monitoring program	One-time inspection activity will verify the effectiveness of the diesel fuel monitoring aging management programs by confirming that unacceptable loss of material is not occurring.

Oil analysis program	One-time inspection activity will verify the effectiveness of the oil analysis aging management programs by confirming that unacceptable cracking, loss of material, and fouling is not occurring.
Water chemistry control program	One-time inspection activity will verify the effectiveness of the water chemistry control – BWR aging management program by confirming that unacceptable cracking, loss of material, and fouling is not occurring.

The inspection will be performed within the ten years prior to the period of extended operation. This program cannot be used for structures or components with known age-related degradation or when the environment in the period of extended operation is not expected to be equivalent to that in the prior 40 years

A.1.34 One-Time Inspection – Small-Bore Piping Program

The One-Time Inspection – Small-Bore Piping Program augments ASME Code, Section XI requirements and is applicable to small-bore ASME Code Class 1 piping and components with a nominal pipe size diameter less than 4 inches (NPS < 4) and greater than or equal to NPS 1 in systems that have not experienced cracking of ASME Code Class 1 small-bore piping. The program can also be used for systems that have experienced cracking but have implemented design changes to effectively mitigate cracking.

This program provides a one-time volumetric inspection of a sample of these Class 1 piping locations that are susceptible to cracking. The program includes pipes, fittings, branch connections, and all full and partial penetration (socket) welds.

GGNS will volumetrically examine 10%, with a maximum of 25, of the socket welds and 10%, with a maximum of 25, of the butt welds within the population of ASME Class 1 small bore piping welds.

For inspections of ASME Class 1 socket welds, volumetric or opportunistic destructive examination will be performed. For inspections of full penetration welds, volumetric examinations will be performed. For socket welds, credit for two volumetric examinations will be taken in the event a destructive examination is performed because more information can be obtained from a destructive examination.

This program includes a statistically significant sampling approach. Sample selection is based on susceptibility to stress corrosion, cyclic loading (including thermal, mechanical, and vibration fatigue), or thermal stratification and thermal turbulence.

The program includes measures to verify that degradation is not occurring, thereby either confirming that there is no need to manage aging-related degradation or validating the effectiveness of any existing program for the period of extended operation. If evidence of cracking is revealed by this one-time inspection, follow-up periodic inspection will be managed by a plant-specific program.

The inspection will be performed within the six-year period prior to the period of extended operation.

A.1.35 Periodic Surveillance and Preventive Maintenance Program

The Periodic Surveillance and Preventive Maintenance Program manages aging effects not managed by other aging management programs, including loss of material due to erosion, loss of material due to recurring internal corrosion, cracking, loss of coating integrity, and change in material properties.

Inspections occur at least once every five years during the period of extended operation, with the exception of inspections of MIC and coating inspections for which frequency is based on inspection results. Visual or other NDE inspections of components in the low pressure core spray, residual heat removal, pressure relief, reactor core isolation cooling, high pressure core spray, and floor and equipment drains systems and the containment building gaskets/seals are performed every five years. Visual or other NDE inspections of a representative sample of internal surfaces of components in the control rod drive, circulating water, and floor and equipment drains systems are performed every five years.

UT or RT wall thickness measurements of selected components of the circulating water, standby service water, plant service water and fire protection systems are performed periodically as necessary to assure minimum pipe wall thickness is maintained. The most susceptible locations will be selected for inspection based on pipe configuration, flow conditions, and operating history. A minimum of five MIC degradation inspections in the collective set of systems will be performed per cycle until MIC no longer meets the criteria for recurring internal corrosion. The scope of MIC examinations will be expanded if substantial MIC is detected during inspections. Scope expansion includes consideration of other locations for additonal sampling such as similar components in the same or redundant trains. Substantial MIC is considered an increased rate of detection of new MIC sites, increased rates of wall thinning at known sites, or unexpected piping wall loss that results in wall thickness near or below code minimum wall thickness.

During the 10-year period prior to the period of extended operation, visual inspections will be performed of coated internal surfaces. Subsequent coating inspections will be performed based on inspection results as follows.

i. If no peeling, delamination, blisters, or rusting are observed, and any cracking and flaking has been found acceptable, subsequent inspections will be performed at least once every 6 years. If the coating is inspected on one train and no indications are found, and if the redundant train has the same coating and turbulent flow is not present, then the redundant train need not be inspected during that inspection interval.

ii. If the inspection results do not meet (i) and a coating specialist has determined that no remediation is required, then subsequent inspections will be conducted on an every other refueling outage interval.

iii. If the inspection results do not meet (i) and a coating specialist determines remediation is required, then the coated components can only be returned to service if the following actions are performed: (1) any blistering in excess of a few small intact blisters, or blisters not completely surrounded by coating bonded to the substrate is removed, (2) any delaminated or peeled coating is removed, (3) the exposed underlying coating is verified to be securely bonded to the substrate at a minimum of three locations as determine by adhesion testing endorsed by Regulatory Guide (RG) 1.54 adjacent to the defective area, (4) the outer most coating is feathered and the remaining outermost coating is determined to be securely bonded to the coating below via adhesion testing endorsed by RG 1.54, (5) ultrasonic testing is performed to ensure the component meets the minimum wall thickness requirements, (6) an evaluation is performed within two years and every two years until the coating is repaired, replaced or removed.

During the 10-year period prior to the period of extended operation, visual inspections will be performed of the internally coated surfaces for components in this program. A qualified coating specialist will determine which of the following methods should be used to determine the condition of the coating and the condition of the component under the degraded coating when conditions such as cracking, peeling, blisters, delamination, rust or flaking are identified during the visual examination.

1. Lightly tapping and scraping the coating to determine the coating integrity.
2. Wet-sponge testing or dry film testing to identify holidays in the coating.
3. Adhesion testing in accordance with ASTM D3359, ASTM D4541, or equivalent testing endorsed by RG 1.54 at a minimum of three locations adjacent to the defective area.
4. Ultrasonic testing to determine if the component's wall thickness meets the minimum thickness criteria.

Coating inspections will cover all accessible internal coated surfaces of applicable tanks and heat exchangers. For areas not readily accessible for direct inspection, such as small pipe lines, heat exchangers and other equipment, consideration will be given to the use of remote or robotic inspection tools. For internal coatings of piping, inspections will cover 50 percent of accessible coated piping within the system or a minimum of 73 locations of 360 degrees of one linear foot for

each combination of type of coating, material the coating is protecting, and environment. Inspection locations of coated piping will be based on coating degradation susceptibility, operating experience, vendor recommendation, and safety significance.

Individuals performing coating inspections are certified to ANSI N45.2.6, “Qualifications of Inspection, Examination, and Testing Personnel for Nuclear Power Plants,” and shall be required to review at least two previous inspection reports when available. A nuclear coatings subject matter expert qualified in accordance with ASTM D 7108-05, “Standard Guide for Establishing Qualifications for a Nuclear Coatings Specialist,” will evaluate inspection findings and prepare post-inspection reports

Coating inspection reports will include lists of locations identified with coating degradation including, where possible, photographs indexed to inspection location, and a prioritization of the repair areas into areas that must be repaired before returning the system to service and areas where coating repair can be postponed to a subsequent inspection or repair opportunity.

Loss of coating integrity acceptance criteria are

1. Indications of peeling and delamination are not acceptable.
2. Blisters are evaluated by a coating specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 including staff limitations associated with use of a particular standard. Blisters should be limited to a few intact small blisters that are completely surrounded by sound coating/lining bonded to the substrate. Blister size and frequency should not be increasing between inspections (e.g., reference ASTM 0714-02. "Standard Test Method for Evaluating Degree of Blistering of Paints").
3. Indications such as cracking, flaking, and rusting are to be evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 including staff limitations associated with the use of a particular standard.
4. Minor cracking and spalling of cementitious coatings/linings is acceptable provided there is no evidence that the coating/lining is debonding from the base material.
5. As applicable, wall thickness measurements, projected to the next inspection, meet design minimum wall requirements.
6. Adhesion testing results, when conducted, meet or exceed the degree of adhesion recommended in plant-specific design requirements specific to the coating/lining and substrate.

In the event the base metal is exposed and the visual inspection identifies corrosion, this inspection finding will be entered into the Corrective Action Program. An evaluation will confirm the component remains acceptable for continued service. As necessary, a volumetric examination will be performed to ensure there is sufficient wall thickness so that the component remains capable of performing its intended function. If repair or replacement of the coating is postponed, the evaluation will consider the minimum wall thickness requirements and the rate of corrosion and confirm the

component remains acceptable for continued service until the next inspection or repair opportunity, which will be within two years.

Credit for program activities has been taken in the aging management review of the following systems and structures.

- Gasket/seal for upper containment pool gates in containment building.
- Low pressure core spray system (LPCS) piping passing through the waterline region of suppression pool.
- Residual heat removal (RHR) system piping passing through the waterline region of suppression pool.
- Pressure relief system piping passing through the waterline region of the suppression pool.
- Reactor core isolation cooling (RCIC) system piping passing through the waterline region of the suppression pool.
- Control rod drive (CRD) system piping.
- Circulating water system piping and valve bodies.
- Floor and equipment drain system piping, drain housings, and valve bodies.
- Piping adjacent to the high pressure, intermediate pressure, and low pressure condenser shells in the circulating water system.
- High pressure core spray (HPCS) system piping passing through the waterline region of the suppression pool.
- Floor and equipment drain system piping below the waterline in the in-scope sumps.
- Moisture separator-reheater shell in the moisture separator-reheater vents and drains system.
- Piping components of the circulating water, standby service water, plant service water, and fire protection systems.
- Fire protection system internally coated piping.
- Reactor water cleanup system internally coated tank
- CRD maintenance facility, flush tank filter and leak test system internally coated tanks
- Condensate and feedwater system internally coated tank
- Condensate cleanup internally coated tanks
- Component cooling water internally coated tank
- Turbine building cooling water internally coated tank
- Domestic water system internally coated tank
- Plant chilled water system internally coated tank
- Drywell chilled water system internally coated heat exchanger and tank
- Standby diesel generator system internally coated tanks
- HPCS diesel generator system internally coated tanks
- Combustible gas control system internally coated heat exchangers
- Control room HVAC system internally coated heat exchangers

The Periodic Surveillance and Preventive Maintenance Program will be enhanced as follows.

- Revise program guidance documents as necessary to include all activities provided in the program description above.

This enhancement will be implemented prior to the period of extended operation.

A.1.36 Protective Coating Monitoring and Maintenance Program

The Protective Coating Monitoring and Maintenance Program monitors and maintains service level I coatings inside containment. The program assesses coating condition through visual inspections.

The Protective Coating Monitoring and Maintenance Program will be enhanced as follows.

- Revise program documents to include parameters monitored or inspected per the guidance provided in ASTM D5163-08.
- Revise program documents to provide for inspection of coatings near sumps or screens associated with the emergency core cooling system.
- Revise program documents to include acceptance criteria per ASTM D 5163-08.

Enhancements will be implemented prior to the period of extended operation.

A.1.37 Reactor Head Closure Studs Program

The Reactor Head Closure Studs Program manages cracking and loss of material for reactor head closure stud bolting using inservice inspection and preventive measures. ASME Section XI examination and inspection requirements specified in Table IWB-2500-1 are used. The program also relies on recommendations to address reactor head closure stud bolting degradation listed in NUREG-1339 and NRC Regulatory Guide 1.65.

A.1.38 Reactor Vessel Surveillance Program

The Reactor Vessel Surveillance Program manages reduction of fracture toughness for reactor vessel beltline materials using material data and dosimetry. The program includes all reactor vessel beltline materials as defined by 10 CFR 50 Appendix G, Section II.F, and complies with 10CFR50, Appendix H for vessel material surveillance. The NRC staff has approved an integrated surveillance program for the period of extended operation (ISP(E)), based on BWRVIP-86, Revision 1.

The Reactor Vessel Surveillance Program will be enhanced as follows.

- Ensure that the additional requirements of the ISP(E) specified in BWRVIP-86, Revision 1, including the conditions of the final NRC safety evaluation for BWRVIP-116 incorporated in BWRVIP-86, Revision 1, will be addressed before the period of extended operation.

- Ensure that new fluence projections through the period of extended operation and the latest vessel beltline ART Tables are provided to the BWRVIP prior to the period of extended operation.

These enhancements will be implemented prior to the period of extended operation.

Although not scheduled for removal and testing for the integrated surveillance program as delineated in BWRVIP-86, Revision 1, the surveillance capsules at GGNS may be required for contingencies of the program. Consequently, any changes to the capsule withdrawl schedule, including spare capsules, must be approved by the NRC prior to implemenation; and untested capsules placed in storage must be maintained for future insertion.

A.1.39 RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program

The RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program is an existing program that requires periodic monitoring of water-control structures so that the consequences of age-related deterioration and degradation can be prevented or mitigated in a timely manner. The program contains guidance on engineering data compilation, inspection activities, technical evaluation, inspection frequency, and the content of inspection reports.

The RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program will be enhanced as follows.

- Accessible structures will be monitored on a frequency not to exceed five years, consistent with the frequency for implementing the requirements of RG 1.127.

- Perform periodic sampling, testing, and analysis of ground water chemistry for pH, chlorides, and sulfates on a frequency of at least every five years.

- Include quantitative acceptance criteria for evaluation and acceptance based on the guidance provided in ACI 349.3R.

Enhancements will be implemented prior to the period of extended operation.

A.1.40 Selective Leaching Program

The Selective Leaching Program includes a one-time visual inspection of selected components coupled with hardness measurement or other mechanical examination techniques to determine whether loss of material is occurring due to selective leaching.

This inspection will be performed within the five years prior to the period of extended operation.

A.1.41 Service Water Integrity Program

The Service Water Integrity Program manages loss of material and fouling in open-cycle cooling water systems as described in the GGNS response to NRC GL 89-13. The program also includes inspections for loss of material due to erosion and loss of internal coating integrity. In addition, the program includes inspections of coatings for submerged piping in the standby service water (SSW) basin. The frequency of these inspections is based on the inspection results.

During the l0-year period prior to the period of extended operation, visual inspections will be performed of coated internal surfaces of standby service water system components. Subsequent coating inspections will be performed based on inspection results as follows.

i. If no peeling, delamination, blisters, or rusting are observed, and any cracking and flaking has been found acceptable, subsequent inspections will be performed at least once every 6 years. If the coating is inspected on one train and no indications are found, and, if the redundant train has the same coating and turbulent flow is not present, then the redundant train need not be inspected during that inspection interval.

ii. If the inspection results do not meet (i) and a coating specialist has determined that no remediation is required, then subsequent inspections will be conducted on an every other refueling outage interval.

iii. If the inspection results do not meet (i) and a coating specialist determines remediation is required, then the coated components can only be returned to service if the following actions are performed (1) any blistering in excess of a few small intact blisters, or blisters not completely surrounded by coating bonded to the substrate is removed, (2) any delaminated or peeled coating is removed, (3) the exposed underlying coating is verified to be securely bonded to the substrate at a minimum of three locations as determine by adhesion testing endorsed by Regulatory Guide (RG) 1.54 adjacent to the defective area, (4) the outer most coating is feathered and the remaining outermost coating is determined to be securely bonded to the coating below via adhesion testing endorsed by RG 1.54, (5) ultrasonic testing is performed to ensure the component meets the minimum wall thickness requirements, (6) an evaluation is performed within two years and every two years until the coating is repaired, replaced or removed.

The Service Water Integrity Program will be enhanced as follows.

- Revise Service Water Integrity Program documents to include inspections for loss of material due to erosion.

- Revise Service Water Integrity Program documents to include visual inspections for loss of coating Integrity during the 10-year period prior to the period of extended operation. Include provisions to specify subsequent coating inspections based on inspection results as follows.

  i. If no peeling, delamination, blisters, or rusting are observed, and any cracking and flaking has been found acceptable, subsequent inspections will be performed at least once every 6 years. If the coating is inspected on one train and no indications are found, and the redundant train has the same coating and turbulent flow is not present, then the redundant train need not be inspected during that inspection interval.

  ii. If the inspection results do not meet (i) and a coating specialist has determined that no remediation is required, then subsequent inspections will be conducted on an every other refueling outage interval.

  iii. If the inspection results do not meet (i) and a coating specialist determines mediation is required, then the coated components can only be returned to service if the following actions are performed (1) any blistering in excess of a few small intact blisters, or blisters not completely surrounded by coating bonded to the substrate is removed, (2) any delaminated or peeled coating is removed, (3) the exposed underlying coating is verified to be securely bonded to the substrate at a minimum of three locations as determine by adhesion testing endorsed by Regulatory Guide (RG) 1.54 adjacent to the defective area, (4) the outer most coating is feathered and the remaining outermost coating is determined to be securely bonded to the coating below via adhesion testing endorsed by RG 1.54, (5) ultrasonic testing is performed to ensure the component meets the minimum wall thickness requirements, (6) an evaluation is performed within two years and every two years until the coating is repaired, replaced or removed.

- Revise Service Water Integrity Program procedures for inspecting the interior of coated components to include one or more of the following methods to determine the condition of the coating and the condition of the component under the degraded coating when conditions such as cracking, peeling, blisters, delamination, rust or flaking are identified during the visual examination.

  1. Lightly tapping and scraping the coating to determine the coating integrity.
  2. Wet-sponge testing or dry film testing to identify holidays in the coating.

3. Adhesion testing in accordance with ASTM D3359, ASTM D4541, or equivalent testing endorsed by RG 1.54 at a minimum of three locations adjacent to the defective area.
4. Ultrasonic testing to determine if the component's wall thickness meets the minimum thickness criteria.

- Revise Service Water Integrity Program documents to visually inspect 50 percent of coated internal surfaces of piping or a minimum of 73 locations of 360 degrees of one linear foot for each combination of type of coating, material the coating is protecting, and environment. Inspection locations will be based on coating degradation susceptibility, operating experience, vendor recommendation and safety significance. Inspect all accessible coated internal surfaces of tanks.

- Revise Service Water Integrity Program documents to include the following coating integrity acceptance criteria: (1) peeling and delamination are not acceptable, (2) cracking is not acceptable if accompanied by delamination or loss of adhesion, and (3) blisters are limited to a few small intact blisters that are completely surrounded by sound coating bonded to the surface.

- Revise Service Water Integrity Program documents to include the following coating integrity corrective actions: In the event peeling, delamination, cracking, or loss of adhesion is identified, follow-up evaluations including adhesion testing endorsed by RG 1.54 will be performed. In the event the base metal is exposed and the visual inspection identifies corrosion, this inspection finding will be entered into the Corrective Action Program, and an evaluation will confirm the component remains acceptable for continued service. As necessary, a volumetric examination will be performed to ensure there is sufficient wall thickness so that the component remains capable of performing its intended function. If repair or replacement of the coating is postponed, the evaluation will consider the minimum wall thickness requirements and the rate of corrosion and confirm the component remains acceptable for continued service until the next inspection or repair opportunity, which will be within two years.

- Revise Service Water Integrity Program documents to specify a review of at least the two previous coating inspection results prior to conducting a coating inspection.

- Revise Service Water Integrity Program procedures to ensure coating inspections are performed by individuals certified to ANSI N45.2.6, "Qualifications of Inspection, Examination, and Testing Personnel for Nuclear Power Plants."

- Revise Service Water Integrity Program procedures to ensure that a nuclear coatings specialist qualified in accordance with ASTM D 7108-05, "Standard Guide for Establishing Qualifications for a Nuclear Coatings Specialist," will evaluate inspection finding and prepare post-inspection reports.

- Revise Service Water Integrity Program documents to state that coating inspection reports will include lists of locations identified with coating deterioration including, where possible, photographs indexed to inspection location, and a prioritization of the repair areas into areas that must be repaired before returning the system to service and areas where coating repair can be postponed to the next inspection or repair opportunity~~.~~, which will be within two years.

- Revise Service Water Integrity Program procedures to ensure degraded coating/lining will be evaluated for potential flow blockage downstream prior to returning a coated component to service. Any coating that is found degraded and returned to service prior to repair or replacement will be evaluated by a coating specialist qualified in accordance with ASTM International standards endorsed by RG 1.54. The evaluation considers the effect of the coating/lining failure on the component’s intended function, problems identified during prior inspections, repair methods used during prior repairs and known service history of the original coating.

These enhancements will be implemented prior to May 1, 2024.

A.1.42 <u>Structures Monitoring Program</u>

The Structures Monitoring Program manages the effects of aging on structures and structural components, including structural bolting, within the scope of license renewal. The program was developed based on guidance in Regulatory Guide 1.160 Revision 2, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," and NUMARC 93-01 Revision 2, "Industry Guidelines for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," to satisfy the requirement of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants."

The Structures Monitoring Program will be enhanced as follows.

- Clarify that the scope includes the following in-scope structures and structural components.
    - Auxiliary Building (GGN2)
    - Containment Building (GGN 2)
    - Control House - Switchyard
    - Culvert No. 1 and drainage channel
    - Manholes and duct banks
    - Radioactive waste building pipe tunnel
    - Turbine Building (GGN2)
- Clarify that the scope includes the following in-scope structural components.
    - Anchor bolts
    - Anchorage / embedments

- Base plates
- Basin debris screen and grating
- Battery racks
- Beams, columns, floor slabs and interior walls
- Cable tray and cable tray supports
- Component and piping supports
- Conduit and conduit supports
- Containment sump liner and penetrations
- Containment sump structures
- Control room ceiling support system
- Cooling tower drift eliminators
- Cooling tower fill
- CST/RWST retaining basin (wall)
- Diesel fuel tank access tunnel slab
- Drainage channel
- Drywell electrical penetrations sleeves
- Drywell equipment hatch
- Drywell floor slab (concrete)
- Drywell head
- Drywell head access manway
- Drywell liner plate
- Drywell mechanical penetration sleeves
- Drywell personnel access lock
- Drywell wall (concrete)
- Duct banks
- Electrical and instrument panels and enclosures
- Equipment pads/foundations
- Exterior walls
- Fan stack grating
- Fire proofing
- Flood curbs
- Flood retention materials (spare parts)
- Flood, pressure and specialty doors
- Floor slab
- Foundations
- HVAC duct supports
- Instrument line supports
- Instrument racks, frames and tubing trays
- Interior walls
- Main steam pipe tunnel
- Manholes
- Manways, hatches, manhole covers, and hatch covers
- Metal siding
- Missile shields

- Monorails
- Penetration sealant (flood, radiation)
- Penetration sleeves (mechanical/electrical not penetrating primary containment boundary)
- Pipe whip restraints
- Pressure relief panels
- Reactor pedestal
- Reactor shield wall (steel portion)
- Roof decking
- Roof hatches
- Roof membrane
- Roof slabs
- RPV pedestal sump liner and penetrations
- Seals and gaskets (doors, manways and hatches)
- Seismic isolation joint
- Stairway, handrail, platform, grating, decking, and ladders
- Structural bolting
- Structural steel, beams, columns, and plates
- Sumps and sump liners
- Support members: welds, bolted connections, support anchorages to building structure
- Support pedestals
- Transmission towers (see Note 1)
- Upper containment pool floor and walls
- Vents and louvers
- Weir wall liner plate

Note 1: The inspections of these structures may be performed by the transmission personnel. However, the results of the inspections will be provided to the GGNS Structures Monitoring Program owner for review.

- Clarify the term "significant degradation" to include the following: "that could lead to loss of structural integrity...."
- Include guidance to perform periodic sampling and analysis of ground water chemistry for pH, chlorides, and sulfates on a frequency of at least once every five years.
- Include an inspection for missing nuts for the structural connections.
- Include monitoring of sliding/bearing surfaces, such as lubrite plates, for loss of material due to wear or corrosion, debris, or dirt. The program will be enhanced to include monitoring elastomeric vibration isolators and structural sealants for cracking, loss of material, and hardening.

- Include inspection requirements for vibration isolators will be enhanced to include augmented inspections by feel or touch to detect hardening, if the vibration isolation function is suspect.

- Require inspections every five years for structures and structural components within the scope of license renewal.

- Prescribe acceptance criteria based on information provided in industry codes, standards, and guidelines, including NEI 96-03, ACI 201.1R-92, ANSI/ASCE 11-99 and ACI 349.3R-96. Industry and plant-specific operating experience will also be considered in the development of the acceptance criteria.

- Require direct visual examinations when access is sufficient for the eye to be within 24-inches of the surface to be examined and at an angle of not less than 30º to the surface. Mirrors may be used to improve the angle of vision and accessibility in constricted areas.

- Specify that remote visual examination may be substituted for direct examination. For all remote visual examinations, optical aids such as telescopes, borescopes, fiber optics, cameras, or other suitable instruments may be used provided such systems have a resolution capability at least equivalent to that attainable by direct visual examination.

- Include periodically inspecting the leak chase system associated with the upper containment pool and spent fuel pool to ensure the tell-tales are free of significant blockage. The inspection will also inspect concrete surfaces for degradation where leakage has been observed, in accordance with this Program.

- Include instructions to augment the visual examinations of roof membranes, and seals and gaskets (doors, manways, and hatches) with physical manipulation of at least 10 percent of available surface area.

Enhancements will be implemented prior to the period of extended operation.

A.1.43 <u>Water Chemistry Control – BWR Program</u>

The Water Chemistry Control – BWR Program manages loss of material, cracking, and fouling in components exposed to a treated water environment by maintaining the concentration of contaminants below system specific limits based on EPRI guideline, BWRVIP-190.

The One-Time Inspection Program utilizes inspections or non-destructive evaluations of representative samples to verify that the Water Chemistry Control – BWR Program has been effective at managing aging effects.

A.1.44 Water Chemistry Control – Closed Treated Water Systems Program

The Water Chemistry Control – Closed Treated Water Systems Program manages loss of material, cracking, and fouling in components exposed to a treated water environment, through monitoring and control of water chemistry, as well as visual inspections.

The Water Chemistry Control – Closed Treated Water Systems Program will be enhanced as follows.

- Revise the water chemistry procedure for closed treated water systems to align the water chemistry control parameter limits with those of EPRI 1007820.
- Provide a corrosion inhibitor for the engine jacket water on the engine-driven fire water pump diesels in accordance with industry guidelines and vendor recommendations.
- Provide periodic flushing of the engine jacket water and cleaning of heat exchanger tubes for the engine-driven fire water pump diesels in accordance with industry guidelines and vendor recommendations.
- Provide testing of the engine jacket water for the engine-driven fire water pump diesels at least annually.
- Conduct inspections whenever a boundary is opened for the following systems.
    - Drywell chilled water (DCW, system P72)
    - Plant chilled water (PCW, system P71)
    - Diesel generator cooling water subsystem for Division I and II standby diesel generators
    - Diesel engine jacket water for engine-driven fire water pumps
    - Diesel generator cooling water subsystem for Division III (HPCS) diesel generator
    - Turbine building cooling water (TBCW, system P43)
    - Component cooling water (CCW, system P42)

  These inspections will be conducted in accordance with applicable ASME Code requirements, industry standards, and other plant-specific inspection and personnel qualification procedures that are capable of detecting corrosion or cracking.
- Inspect a representative sample of piping and components at a frequency of once every ten years for the following systems.
    - Drywell chilled water (DCW, system P72)
    - Plant chilled water (PCW, system P71)
    - Diesel generator cooling water subsystem for Division I and II standby diesel generators
    - Diesel engine jacket water for engine-driven fire water pumps

- Diesel generator cooling water subsystem for Division III (HPCS) diesel generator
- Turbine building cooling water (TBCW, system P43)
- Component cooling water (CCW, system P42)

Components inspected will be those with the highest likelihood of corrosion or cracking. A representative sample is 20% of the population (defined as components having the same material, environment, and aging effect combination) with a maximum of 25 components. The inspection methods will be in accordance with applicable ASME Code requirements, industry standards, or other plant-specific inspection and personnel qualification procedures that ensure the capability of detecting corrosion or cracking.

Enhancements will be implemented prior to the period of extended operation.

A.2 EVALUATION OF TIME-LIMITED AGING ANALYSES

In accordance with 10 CFR 54.21(c), an application for a renewed license requires an evaluation of time-limited aging analyses for the period of extended operation. The following time-limited aging analyses have been identified and evaluated to meet this requirement.

A.2.1 Reactor Vessel Neutron Embrittlement

The reactor vessel neutron embrittlement time-limited aging analyses including consideration for extended power uprate (EPU) either have been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii) or will be managed for the period of extended operation in accordance with 10 CFR 54.24(c)(1)(iii) as summarized below.

Based on the plant operating history, a projected EFPY value of 54 EFPY is used to evaluate reactor vessel neutron embrittlement time-limited aging analyses.

A.2.1.1 Reactor Vessel Fluence

Calculated fluence is based on a time-limited assumption defined by the operating term. Therefore, analyses that evaluate reactor vessel neutron embrittlement based on calculated fluence are time-limited aging analyses.

High-energy (> 1 MeV) neutron fluence for the nozzles, welds and shells of the reactor pressure vessel (RPV) beltline region was determined using the MPM method for neutron flux calculation documented in the GGNS license amendment request (LAR) “Application to Revise Grand Gulf Nuclear Station Unit 1's Current Fluence Methodology from 0 Effective Full Power Years (EFPY) Through the End of Extended Operations to a Single Fluence Method.”

The neutron fluence calculation results are inputs into fracture toughness analyses that consider the effects of aging due to exposure to neutron irradiation and are evaluated as TLAAs. The effects of aging due to neutron irradiation are considered in the neutron embrittlement TLAAs for the reactor vessel (e.g., upper-shelf energy analysis and P-T limits analysis). The neutron fluence analysis has been projected to the end of the period of extended operation in accordance with 54.21(c)(1)(ii).

A.2.1.2 Pressure-Temperature Limits

Appendix G of 10 CFR 50 requires that the reactor vessel remain within established pressure-temperature (P-T) limits during boltup, hydro-test, pressure tests, normal operation, and anticipated operational occurrences. These limits are calculated using materials and fluence data, including data obtained through the Reactor Vessel Surveillance Program.

The P-T limit curves will continue to be updated, as required by Appendix G of 10 CFR Part 50 and in accordance with Grand Gulf Technical Specification 5.6.6, assuring that limits remain valid through the period of extended operation.

The time-limited aging analyses for reactor vessel pressure-temperature limits will be managed for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A.2.1.3 Upper-Shelf Energy

The predictions for percent drop in upper shelf energy (USE) values were projected to 54 EFPY using projected beltline fluence values, chemistry and surveillance data, and un-irradiated USE information in accordance with Regulatory Guide 1.99. All projected USE values for 54 EFPY remain above the 50 ft-lb minimum acceptable value or have been demonstrated acceptable through an equivalent margin analysis as specified in Appendix G of 10 CFR 50.

The time-limited aging analyses for upper shelf energy have been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.2.1.4 Reactor Vessel Circumferential Weld Inspection Relief

The GGNS reactor pressure vessel circumferential weld parameters at 54 EFPY will remain within the NRC's (64 EFPY) bounding parameters from the BWRVIP-05 SER. The fact that the values projected to the end of the period of extended operation are less than the 64 EFPY value provided by the NRC leads to the conclusion that the GGNS RPV conditional failure probability is less than the conditional failure probability of the NRC analysis. As such, the conditional probability of failure for circumferential welds remains below that determined during the NRC's final safety evaluation of BWRVIP-05.

The reactor vessel circumferential weld inspection relief for the extended operating period will be submitted to the NRC in accordance with 10 CFR 50.55(a).

The effects of aging associated with the time-limited aging analysis for reactor vessel circumferential weld inspection relief will be managed in accordance with 10 CFR 54.21(c)(1)(iii).

A.2.1.5 Reactor Vessel Axial Weld Failure Probability

The NRC SER for BWRVIP-74-A evaluated the failure frequency of axially oriented welds in BWR reactor vessels. Applicants for license renewal must evaluate axially oriented RPV welds to show that their failure frequency remains below the value calculated in the BWRVIP-74 SER. The SER states that an acceptable way to do this is to show that the mean RT_{NDT} of the limiting axial beltline weld at the end of the period of extended operation is less than the values specified in the SER.

The projected 54 EFPY GGNS mean ART is less than the bounding value shown in the NRC SER for BWRVIP-74.

Reactor vessel axial weld TLAA has been projected through the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.2.1.6 Reactor Pressure Vessel Core Reflood Thermal Shock Analysis

General Electric Report NEDO-10029 is referenced in Section 5.3.3 of the UFSAR. NEDO-10029 addressed the concern for brittle fracture of the reactor pressure vessel due to reflood following a postulated loss of coolant accident (LOCA). In addition to the NEDO-10029 that is listed in the UFSAR, there is a more recent analysis of the BWR-6 vessels (Ranganath, S., "Fracture Mechanics Evaluation of a Boiling Water Reactor Vessel Following a Postulated Loss of Coolant Accident," Fifth International Conference on Structural Mechanics in Reactor Technology, Berlin, Germany, August 1979). The more recent analysis is appropriate for the GGNS reactor pressure vessel because it evaluates the bounding LOCA event, a main steam line break, for a BWR-6 vessel design.

This analysis shows that when the peak stress intensity occurs at approximately 300 seconds after the LOCA, the temperature inside the vessel wall is approximately 400ºF. The maximum ART value calculated for the GGNS RPV beltline material is 51.1ºF. Using the equation for K_{IC} presented in Appendix A of ASME Section XI and the maximum ART value, the material reaches upper shelf at approximately 155.4ºF, which is well below the minimum 400ºF temperature predicted for the thermal shock event at the time of peak stress intensity. Therefore, the revised analysis has projected the TLAA through the period of extended operation. The time-limited aging analysis for Reactor Pressure Vessel Core Reflood Thermal Shock Analysis has been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.2.2 Metal Fatigue

A.2.2.1 Class 1 Metal Fatigue

Fatigue evaluations were performed in the design of the GGNS Class 1 components in accordance with their design requirements. ASME Section III fatigue evaluations are contained in analyses and stress reports, and because they may be based on a number of transient cycles assumed for a 40-year operating term, these evaluations are considered time-limited aging analyses.

Design cyclic loadings and thermal conditions for the Class 1 components are defined by the applicable design specifications for each component. The original design specifications provided a set of transients that were used in the design of the components and are included as part of each component analysis or stress report.

The Fatigue Monitoring Program tracks and evaluates the cycles and requires corrective actions if limits are approached.

Reactor Vessel

As described in UFSAR Section 5.3.3.3, the reactor pressure vessel is a vertical, cylindrical pressure vessel of welded construction fabricated in accordance with ASME Code, Section III,

Class 1 requirements. Fatigue evaluations for the reactor vessel were performed as part of the vessel design. The fatigue analyses of the reactor vessel are considered time-limited aging analyses because they are based on numbers of design cycles that were expected to occur in 40 years of operation.

GGNS will monitor these transient cycles using the Fatigue Monitoring Program and assure that action is taken if any of the actual cycles approach their analyzed numbers. As such, the Fatigue Monitoring Program will manage the effects of aging due to fatigue on the reactor vessel in accordance with 10 CFR 54.21(c)(1)(iii).

Reactor Vessel Feedwater Nozzle

As described in UFSAR Section 5.3.3.1.4.5.1, GGNS implemented a plant modification prior to plant operation to eliminate concerns identified in previous BWR designs. A second piston ring and triple thermal sleeves have been incorporated in the design for Grand Gulf.

The analysis of the modified feedwater nozzle included fatigue from potential rapid cycling behind the thermal sleeves. Therefore, for the FW nozzle there is a location-specific rapid cycling fatigue usage that added to the cycle-based fatigue. The usage is postulated based on time and feedwater temperature in order to include the rapid cycling effect.

The feedwater nozzle is one of the locations that will be reevaluated for environmental assisted fatigue, and the reanalysis will consider the effects of potential rapid cycling. The feedwater nozzle reanalysis will include a location-specific rapid cycling fatigue usage that is added to the cycle-based fatigue usage. The usage will be postulated based on time and feedwater temperature in order to include the rapid cycling effect. This action will be completed under the Fatigue Monitoring Program. As such, the effects of fatigue on the feedwater nozzles will be managed for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

Reactor Vessel Internals

A general assembly drawing of the important RPV internals components is shown in UFSAR Figure 3.9-8. Fatigue evaluations for the reactor vessel internals were performed as part of the internals design. The fatigue analyses of the reactor vessel internals are considered time-limited aging analyses because they are based on numbers of design cycles that were expected to occur in 40 years of operation. The fatigue analyses of the reactor vessel internals were reviewed during the extended power uprate.

GGNS will monitor transient cycles using the Fatigue Monitoring Program and assure that action is taken if any of the actual cycles approach their analyzed numbers. As such, the Fatigue Monitoring Program will manage the effects of aging due to fatigue on the reactor vessel internals in accordance with 10 CFR 54.21(c)(1)(iii).

Reactor Recirculation Pumps

UFSAR Section 3.9.1.2.1.4 describes the Byron-Jackson recirculation pump fatigue analysis. The fatigue analysis for the reactor recirculation pump casing considered the RCS fatigue transients specified by GE. The analysis justified exempting portions of the case from analysis and determined that the remaining locations met 1974 ASME Section III code fatigue requirements. Usage factors were calculated for several locations in the pump cover that were later reanalyzed due to modifications to install shaft sleeves and modify the seal water heat exchanger.

The Fatigue Monitoring Program will manage the effects of aging due to fatigue on the reactor recirculation pumps in accordance with 10 CFR 54.21(c)(1)(iii).

Control Rod Drives

The Class 1 portions of the control rod drives were analyzed for fatigue. The cumulative usage factors are low and the tracking of cycles under the Fatigue Monitoring Program ensures the fatigue on these components remains acceptable. The Fatigue Monitoring Program will manage the effects of aging due to fatigue on the control rod drives in accordance with 10 CFR 54.21(c)(1)(iii)

Class 1 Piping

The piping specifications for GGNS identified that the ASME Class 1 piping must be analyzed for the transient cycle drawings provided by General Electric. Detailed fatigue analyses were then generated for GGNS to analyze multiple locations on each system within the ASME Class 1 boundary. The fatigue analyses of the Class 1 piping are considered time-limited aging analyses because they are based on numbers of design cycles that were expected to occur in 40 years of operation. GGNS will monitor the cycles actually incurred compared to the cycles analyzed using the Fatigue Monitoring Program and assure that action is taken if the actual cycles approach their analyzed numbers. As such, the Fatigue Monitoring Program will manage the effects of aging due to fatigue on the ASME Section III piping in accordance with 10 CFR 54.21(c)(1)(iii).

A.2.2.2 Non-Class 1 Metal Fatigue

The design of ASME III Code Class 2 and 3 piping systems incorporates the Code stress reduction factor for determining acceptability of piping design with respect to thermal stresses. In general, 7000 thermal cycles are assumed, allowing a stress reduction factor of 1.0 in the stress analyses. GGNS evaluated the validity of this assumption for 60 years of plant operation. The results of this evaluation indicate that the 7000 thermal cycle assumption will not be exceeded for 60 years of operation. Therefore, the pipe stress calculations remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

Non-class 1 components other than piping system components require fatigue analyses if they were built to a section of the code such as ASME Section III, NC-3200 or ASME Section VIII,

Division 2. A review of the non-Class 1 components other than piping identified non-Class 1 fatigue analysis applicable to expansion joints. Design specifications and calculations were identified for expansion joints with fatigue analyses for a bounding number of cycles, which were identified as time limited aging analyses. Evaluation of certain analyses determined the number of analyzed cycles were adequate for 60 years of operation. Therefore, these non-Class 1 expansion joint TLAAs are valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i). The analyses for other expansion joints were projected to 60 years of operation and the resulting CUF values remained less than 1.0. Therefore, these non-Class 1 expansion joint TLAAs have been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.2.2.3 Effects of Reactor Water Environment on Fatigue Life

NUREG/CR-6260 addresses the application of environmental factors to fatigue analyses (CUFs) and identifies locations of interest for consideration of environmental effects. Section 5.6 of NUREG/CR-6260 identified the following component locations to be the most sensitive to environmental effects for newer vintage General Electric plants. These locations and the subsequent calculations are directly relevant to GGNS.

(1) Reactor vessel shell and lower head

(2) Reactor vessel feedwater nozzle

(3) Reactor recirculation piping (including inlet and outlet nozzles)

(4) Core spray line reactor vessel nozzles and associated Class 1 piping

(5) Residual heat removal nozzles and associated Class 1 piping

(6) Feedwater line Class 1 piping

To support the license renewal application GGNS performed a screening evaluation of these six locations using the guidance provided in NUREG-1801 revision 2. This screening has determined there are locations that when the current usage factor is increased to account for the environmental effects, the resulting usage is greater than 1. Prior to the period of extended operation GGNS will update the fatigue usage calculations using refined fatigue analyses to determine valid CUFs less than 1.0 when accounting for the effects of reactor water environment. This includes applying the appropriate F_{en} factors to valid CUFs determined using an NRC-approved version of the ASME code or NRC-approved alternative (e.g., NRC-approved code case). GGNS will review design basis ASME Class 1 component fatigue evaluations to determine whether the locations that have been evaluated for the effects of the reactor coolant environment on fatigue include the limiting component within the reactor coolant pressure boundary. Environmental effects on fatigue for these critical components will be evaluated using one of the following sets of formulae in accordance with the guidance in NUREG-1801, Revision 2, Section X.M1:

Carbon and Low Alloy Steels

- Those provided in NUREG/CR-6583, using the applicable ASME Section III fatigue design curve.
- Those provided in Appendix A of NUREG/CR-6909, using either the applicable ASME Section III fatigue design curve or the fatigue design curve for carbon and low alloy steel provided in NUREG/CR-6909 (Figures A.1 and A.2, respectively, and Table A.1).
- A staff-approved alternative.

Austenitic Stainless Steels

- Those provided in NUREG/CR-5704, using the applicable ASME Section III fatigue design curve.
- Those provided in NUREG/CR-6909, using the fatigue design curve for austenitic stainless steel provided in NUREG/CR-6909 (Figure A.3 and Table A.2).
- A staff-approved alternative.

Nickel Alloys

- Those provided in NUREG/CR-6909, using the fatigue design curve for austenitic stainless steel provided in NUREG/CR-6909 (Figure A.3 and Table A.2).
- A staff-approved alternative.

Future calculation of F_{en} values will incorporate available transient cycle occurrence data during operating times in normal water chemistry (NWC) and hydrogen water chemistry (HWC). If an acceptable CUF cannot be calculated, GGNS will repair or replace the affected locations before exceeding an environmentally adjusted CUF of 1.0.

GGNS will manage the effects of fatigue, including environmentally assisted fatigue, under the Fatigue Monitoring Program for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii). Industry-accepted techniques will be used for consideration of the effects on fatigue of the reactor water environment (environmentally assisted fatigue – EAF), including techniques for incorporating the impact of dissolved oxygen concentration into the calculation of fatigue environmental correction factors.

A.2.3 Environmental Qualification of Electrical Components

The GGNS Environmental Qualification (EQ) of Electric Components Program implements the requirements of 10 CFR 50.49 (as further defined by the Division of Operating Reactors Guidelines, NUREG-0588, and Reg. Guide 1.89). The program requires action before individual components exceed their qualified life. In accordance with 10 CFR 54.21(c)(1)(iii), implementation of the EQ Program provides reasonable assurance that the effects of aging on components associated with

EQ time-limited aging analyses will be adequately managed such that the intended functions can be maintained for the period of extended operation.

A.2.4 Fatigue of Primary Containment, Attached Piping, and Components

Grand Gulf utilizes a BWR Mark III containment. As described in UFSAR Section 3.8.1.3, the containment was initially designed in accordance with the loads defined in GE Topical Report NEDO 11314-08 (GESSAR Appendix 3B). Additional loads initially defined in GE document 22A4365, Interim Containment Loads Report (ICLR), Rev. 2 and later defined by GE document 22A7000, Rev. 2 (GESSAR II, Appendix 3B; Grand Gulf FSAR, Appendix 6D), have been considered for the final design verification of the containment.

UFSAR Appendix 6A, Section 3BA.7.2.2.3 (page 6A-14) identifies the quenchers were designed for a conservatively high value of 18,000 cycles of fatigue.

UFSAR Section 3.8.1.4.2 identifies the analysis of the suppression pool and cylinder wall liner plate. Fatigue analysis for the suppression pool and cylinder wall liner plate was performed using subsections NE and NB of the ASME Code, Section III, Division I, 1971 Edition with Summer of 1973 Addenda.

As shown on UFSAR Figure 3.6A-33, the guard pipe assemblies utilize bellows. Calculations were identified for the bellows on the guard pipe assemblies that analyzed a large number of cycles of flexure due to normal operation and earthquakes and are therefore considered TLAAs.

As shown on UFSAR Figure 9.1-15 and described in UFSAR Section 9.1.4.2.3.11, the GGNS fuel transfer tube also uses bellows. A calculation was identified for the bellows on the transfer tube that analyzed a large number of cycles of flexure due to normal operation or earthquakes and is therefore considered a TLAA.

GGNS will monitor transient cycles using the Fatigue Monitoring Program and assure that action is taken if any of the actual cycles approach their analyzed numbers. As such, the Fatigue Monitoring Program will manage the effects of aging due to fatigue on the primary containment in accordance with 10 CFR 54.21(c)(1)(iii).

A.2.5 Other Plant-Specific TLAA

A.2.5.1 Erosion of the Main Steam Line Flow Restrictors

GGNS UFSAR Section 5.4.4.4 identifies for the stainless steel main steam flow restrictors, "Only very slow erosion will occur with time." The section later postulates that even with an erosion rate of 0.004 inches per year, the increase in choked flow after 40 years would be no more than five percent. This was evaluated as a TLAA.

Entergy Corporation evaluated the erosion-corrosion rate for the main steam flow elements. This analysis considered the specific material present in GGNS flow restrictors and determined the

expected erosion-corrosion rate when operating at the velocities that would be present following EPU. The evaluation determined the expected erosion-corrosion rate would be much less than the conservative value in the UFSAR. Using this value, the expected total erosion after 60 years would remain less than the conservative total erosion value identified in the UFSAR for 40 years.

This analysis has been projected through the period of extended operation in accordance with 10CFR54.21(c)(1)(ii).

A.2.5.2 Determination of Intermediate High-Energy Line Break Locations

UFSAR Section 3.6A.2 identifies for GGNS that the determinations of intermediate high-energy line break locations included an evaluation based on CUFs being less than 0.1 if other stress criteria are also met. The usage factors, as calculated in the design fatigue analyses, account for the design transients assumed for the original 40-year life of the plant. Therefore, the determination of cumulative usage factors used in the selection of postulated high-energy line break locations is considered a TLAA.

The Fatigue Monitoring Program will identify when the transients for high-energy piping systems are approaching their analyzed numbers of cycles. If the design cycles indicate the cycle limit for exceeding a CUF of 0.1 will be exceeded, the design calculations for that system will be reviewed to determine if any additional locations should be designated as postulated high-energy line breaks. If other locations are determined to require consideration as postulated break locations, actions will be taken to address the new break locations.

The determination of intermediate high-energy line break locations is considered a TLAA that is dispositioned by 10 CFR 54.21(c)(1)(iii). The program that will manage this is the Fatigue Monitoring Program.

A.2.5.3 Fluence Effects for the Reactor Vessel Internals

The design specification 22A4052 for the reactor vessel internals components includes requirements beyond the ASME design requirements for austenitic stainless steel base metal components exposed to greater than 1×10^{21} nvt (> 1 MEV) or weld metal greater than 5×10^{20} nvt (> 1 MEV).

Entergy Corporation performed a fluence analysis of the components included in the design specification 22A4052 at EPU operating conditions for 60 years plant life (54 EFPY). Location-specific fluence levels were determined. The internal core support structure components were then evaluated against the irradiation criteria in the design specification. The results of the evaluation were that the GGNS internal core support structure components meet the design specification at EPU operating conditions for 54 EFPY.

Therefore, this analysis has been projected through the period of extended operation in accordance with 10CFR54.21(c)(1)(ii).

A.2.5.4 Fatigue Analysis of Cranes

Cranes that were designed to Crane Manufacturer's Association of America Specification #70 (CMAA-70) have cycles specified as part of their design analysis. While there is no analysis that involves time-limited assumptions defined by the current operating term, for example, 40 years, fatigue evaluations are nevertheless evaluated as TLAAs for cranes that were designed to CMAA-70.

A review of the cranes at GGNS was performed to determine which cranes were designed to CMAA-70. The spent fuel cask crane, new fuel handling crane, and polar crane at GGNS included CMAA-70 in their design specification. The number of load cycles a crane is qualified for under CMAA-70 is 100,000 cycles. The estimated number of lifts for each crane at the end of the period of extended operation is well below the 100,000 cycle limit.

Therefore the expected number of lifts is well below the value specified in CMAA-70, and the crane fatigue evaluation remains valid for the period of extended operation consistent with 10 CFR 54.21(c)(1)(i).

A.3 REFERENCES

A.3-1 Letter GNRO-2011/00093, from GGNS to NRC, License Renewal Application, Grand Gulf Nuclear Station, Unit 1, dated October 28, 2011. ADAMS Accession No. ML11308A052.

A.3-2 NUREG-2211, Safety Evaluation Report Related to the License Renewal of Grand Gulf Nuclear Station, Unit 1, Docket Number 50-416, Entergy Operations, Inc. November 2016. ADAMS Accession No. ML16320A015.

A.3-3 Letter GNRO-2010/00056, from Michael Krupa, Entergy, to USNRC, License Amendment Request, Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1, Dated September 8, 2010.

A.3-4 Letter NRC to GGNS, Grand Gulf Nuclear Station, Unit 1 - Issuance of Amendment Re: Extended Power Uprate (TAC No. ME4679), dated July 18, 2012. ADAMS Accession No. ML121210020.

A.4 LICENSE RENEWAL COMMITMENT LIST

These regulatory commitments must be incorporated into the UFSAR, and any future changes to this action must be evaluated under the criteria of 10 CFR 50.59

Item Number	Commitment	LRA Section	Implementation Schedule	Source
1	Implement the 115 kilovolt (KV) Inaccessible Transmission Cable Program for Grand Gulf Nuclear Station (GGNS) as described in License Renewal Application (LRA) Section B.1.1	B.1.1	Prior to May 1, 2024 or the end of the last refueling outage prior to November 1, 2024, whichever is later.	GNRO-2011/00093
2	Implement the Aboveground Metallic Tanks Program for GGNS as described in LRA Section B.1.2	B.1.2	Prior to May 1, 2024 or the end of the last refueling outage prior to November 1, 2024, whichever is later.	GNRO-2011/00093
3	Enhance the Bolting Integrity Program for GGNS to clarify the prohibition on use of lubricants containing MoS_2 for bolting, and to specify that proper gasket compression will be visually verified following assembly. Enhance the Bolting Integrity Program to include consideration of the guidance applicable for pressure boundary bolting in Regulatory Guide (NUREG) 1339, Electric Power Research Institute (EPRI) NP-5769, and EPRI TR-104213. Enhance the Bolting Integrity Program to include volumetric examination per American Society of Mechanical Engineers (ASME) Code Section IX, Table IWB-2500-1, Examination Category B-G-1, for high-strength closure bolting regardless of code classification.	B.1.3	Prior to May 1, 2024	GNRO-2011/00093
4	Enhance the Boraflex Monitoring Program for GGNS to perform periodic surveillances of the boraflex neutron absorbing material in the spent fuel pool at least once every 5 years using Boron-10 Areal Density Gage for Evaluating Racks (BADGER) testing. RACKLIFE analysis, or an equivalent methodology, will continue to be performed each cycle. This analysis will include a comparison of the RACKLIFE predicted silica to the plant measured silica. This comparison will determine if adjustments to the RACKLIFE loss coefficient are merited. The	B.1.4	Prior to May 1, 2024	GNRO-2011/00093 GNRO-2012-00077

	analysis will include projections to the next planned RACKLIFE analysis date to ensure current Region I storage locations will not need to be reclassified as Region II storage locations in the analysis interval.			
5	Implement the Buried Piping and Tanks Inspection Program for GGNS as described in LRA Section B.1.5. Soil testing will be performed at two locations near the stainless steel condensate storage system piping that is subject to aging management review. Measured parameters will include soil resistivity, bacteria, pH, moisture, chlorides and redox potential. If the soil is determined to be corrosive then the number of inspections will be increased from one to two prior to and during the period of extended operation.	B.1.5	Prior to May 1, 2024 or the end of the last refueling outage prior to November 1, 2024, whichever is later.	GNRO-2011/00093 GNRO-2012/00089
6	Enhance the Boiling Water Reactor (BWR) Vessel Internals Program for GGNS as follows. (a) Evaluate the susceptibility to neutron or thermal embrittlement for reactor vessel internal components composed of CASS, X-750 alloy, precipitation-hardened (PH) martensitic stainless steel(e.g., 15-5 and 17-4 PH steel), and martensitic stainless steel (e.g., 403, 410 and 431 steel). This evaluation will include a plant-specific identification of the reactor vessel internals components made of these materials. (b) Inspect portions of the susceptible components determined to be limiting from the standpoint of thermal aging susceptibility, neutron fluence, and cracking susceptibility (i.e., applied stress, operating temperature, and environmental conditions). The inspections will use an inspection technique capable of detecting the critical flaw size with adequate margin. The critical flaw size will be determined based on the service loading condition and service-degraded material properties. The initial inspection will be performed either prior to or within 5 years after entering the period of extended operation. If cracking is detected after the initial inspection, the frequency of re-inspection will be justified based on fracture toughness properties appropriate for the condition of the component. The sample size for the initial inspection of	B.1.11	Prior to May 1, 2024	GNRO-2011/00093 GNRO-2012/00137 GNRO-2012/00137

	susceptible components will be 100% of the accessible component population, excluding components that may be in compression during normal operations.			
7	Enhance the Compressed Air Monitoring Program for GGNS to apply a consideration of the guidance of ASME OM-S/G-1998, Part 17; ANSI/ISA-S7.0.01-1996; EPRI NP-7079; and EPRI TR-108147 to the limits specified for air system contaminants. Enhance the Compressed Air Monitoring Program to include periodic and opportunistic inspections of accessible internal surfaces of piping, compressors, dryers, aftercoolers, and filters to apply consideration of the guidance of ASME OM-S/G-1998, Part 17 for inspection frequency and inspection methods of these components in the following compressed air systems. • Automatic Depressurization System (ADS) air • Division 1 Diesel Generator Starting Air (D1DGSA) • Division 2 Diesel Generator Starting Air (D2DGSA) • Division 3 Diesel Generator Starting Air (D3DGSA), also known as the HPCS Diesel Generator • Instrument Air (IA)	B.1.12	Prior to May 1, 2024	GNRO-2011/00093
8	Enhance the Diesel Fuel Monitoring Program to include a ten-year periodic cleaning and internal inspection of the fire water pump diesel fuel oil tanks, the diesel fuel oil day tanks for Divisions I, II, III, and the diesel fuel oil drip tanks for Divisions I, II. These cleanings and internal inspections will be performed at least once during the 10-year period prior to the period of extended operation and at succeeding 10-year intervals. If visual inspection is not possible, a volumetric inspection will be performed. Enhance the Diesel Fuel Monitoring Program to include a volumetric examination of affected areas of the diesel fuel tanks if evidence of degradation is	B.1.16	Prior to May 1, 2014 or the end of the last refueling outage prior to November 1, 2024, whichever is later.	GNRO-2011/00093

	observed during visual inspection. The scope of this enhancement includes the diesel fuel oil day tanks (Divisions I, II, III), the diesel fuel oil storage tanks (Divisions I, II, III), the diesel fuel oil drip tanks (Divisions I, II), and the diesel fire pump fuel oil storage tanks, and is applicable to the inspections performed during the 10-year period prior to the period of extended operation and at succeeding 10-year intervals.			
9	Enhance the External Surfaces Monitoring Program to include instructions for monitoring of the aging effects for flexible polymeric components through manual or physical manipulation of the material, including a sample size for manipulation of at least 10 percent of available surface area. Enhance the External Surfaces Monitoring Program as follows. 1. Underground components within the scope of this program will be clearly identified in program documents. 2. Instructions will be provided for inspecting all underground components within the scope of this program during each 5 year period, beginning 10 years prior to entering the period of extended operation. 3. Revise External Surfaces Monitoring Program procedures to specify the following for insulated components. • Periodic representative inspections will be conducted during each 10-year period during the PEO. • For a representative sample of insulated indoor components exposed to condensation (because the component is operated below the dew point), insulation will be removed for visual inspection of the component surface. Inspections will include a minimum of 20 percent of the in-scope piping length for each material type (e.g., steel, stainless steel, copper alloy, aluminum), or for components with a configuration which does not conform to a 1-foot axial length determination (e.g., valve, accumulator), 20 percent of the surface area. Alternatively, insulation will be	B.1.18	Prior to May 1, 2014 or the end of the last refueling outage prior to November 1, 2024, whichever is later.	GNRO-2011/00093 GNRO-2013/00021 GNRO-2014/00030

	removed and a minimum of 25 inspections will be performed that can be a combination of 1-foot axial length sections and individual components for each material type. • Inspection locations will be selected based on the likelihood of corrosion under insulation (CU I). For example, CUI is more likely for components experiencing alternate wetting and drying in environments where trace contaminants could be present and for components that operate for longer periods of time below the dew point. Subsequent inspections can be limited to an examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation, if the following conditions are verified in the initial inspection. ➢ No loss of material due to general. pitting or crevice corrosion, beyond that which could have been present during initial construction, and ➢ No evidence of cracking If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or there is evidence of water intrusion through the insulation (e.g. water seepage through insulation seams/joints), periodic inspections under the insulation will continue as described above. • Removal of tightly adhering insulation that is impermeable to moisture is not required unless there is evidence of damage to the moisture barrier. Tightly adhering insulation is considered a separate population from the remainder of insulation installed on in scope components. The entire population of in-scope accessible piping component surfaces that have tightly adhering insulation will be visually inspected for damage to the moisture barrier at the same frequency as inspections of other types of insulation, These inspections will not be credited towards the inspection quantities for other types of insulation.			

10	Enhance the Fatigue Monitoring Program to monitor and track all critical thermal and pressure transients for all components that have been identified to have a fatigue Time Limited Aging Analysis (TLAA). Enhance the Fatigue Monitoring Program to perform a review of the GGNS high energy line break analyses and the corresponding tracking of associated cumulative usage factors to ensure the GGNS program adequately manages fatigue usage for these locations. Fatigue usage calculations that consider the effects of the reactor water environment will be developed for a set of sample reactor coolant system components. This sample set will include the locations identified in NUREG/CR-6260 and additional plant-specific component locations in the reactor coolant pressure boundary if they are found to be more limiting than those considered in NUREG/CR-6260. F_{en} factors will be determined using the formulae sets listed in Section 4.3.3. If necessary following this analysis, revised cycle limits will be incorporated into the Fatigue Monitoring Program documentation. Enhance the Fatigue Monitoring Program to provide updates of the fatigue usage calculations on an as-needed basis if an allowable cycle limit is approached, or in a case where a transient definition has been changed, unanticipated new thermal events are discovered, or the geometry of components have been modified. The program revision will include providing for the consideration of the recirculation pump fatigue analysis exemption validity if cycles that were input into the exemption evaluation exceed their limits.	B.1.19	Prior to November 1, 2022	GNRO-2011/00093 GNRO-2012/00063
11	Enhance the Fire Protection Program to require visual inspections of the clean agent//CO_2 fire suppression system at least once every fuel cycle to examine for signs of corrosion. Enhance the Fire Protection Program to require visual inspections of fire damper framing at least once every fuel cycle to check for signs of degradation. Enhance the Fire Protection Program to require visual inspection of concrete curbs, manways,	B.1.20	Prior to May 1, 2024	GNRO-2011/00093

	hatches, manhole covers, hatch covers, and roof slabs at least once every fuel cycle to confirm that aging effects are not occurring. Enhance the Fire Protection Program to require an external visual inspection of the CO2 tank at least once every fuel cycle to examine for signs of corrosion.			GNRO-2012/00042
12	The Fire Water System Program will be enhanced as follows. • Revise Fire Water System Program procedures to ensure sprinkler heads are tested or replaced in accordance with NFPA-25 (2011 Edition), Section 5.3.1. • Revise Fire Water System Program procedures to specify replacing any sprinkler that shows signs of leakage or corrosion. • Revise Fire Water System Program procedures to perform a flow blockage evaluation if during main drain testing, the flowing pressure drops more than 10 percent from the flowing pressure observed during the original acceptance test or other previously performed tests at the same location. • Revise Fire Water System Program procedures to ensure there is no flow blockage by visually inspecting the charcoal filter deluge fire water distribution piping when the charcoal is replaced. • Revise Fire Water System Program procedures to perform air flow testing to ensure there are no obstructions downstream of the deluge valves for control room fresh air, auxillary building standby gas, containment cooling system, and containment vent charcoal filter units each refueling cycle. • Revise Fire Water System Program procedures to include periodic internal inspections and documentation of any excessive accumulation of corrosion products or appreciable localized corrosion (e.g., pitting) beyond a normal oxide	B.1.21	Prior to May 1, 2024 or the end of the last refueling outage prior to November 1, 2024, whichever is later.	GNRO-2011/00093 GNRO-2014/00030 GNRO-2014/00076 GNRO-2015/00034 GNRO-2015/00055 GNRO-2015/00079

	layer in the corrective action program and that follow-up volumetric wall thickness examination will be performed as part of the corrective action. • Revise Fire Water System Program procedures to require internal inspections at the end of one fire main and the end of one branch line on two of the wet pipe systems in the auxiliary building, two of the wet pipe systems in the control building, and one wet pipe system in the fire pump house every five years. During each five-year internal inspection period, inspect different wet pipe sprinklers such that internal inspections are performed on all of the wet pipe sprinkler systems in the auxiliary and control buildings every 15 years and in the fire pump house every 10 years. In the event internal obstructions are identified in a building wet pipe system, expand the number of inspections to include all of the wet pipe sprinkler systems in that building. • Revise Fire Water System Program procedures to periodically open a flushing connection at the end of a main and remove a component such as a sprinkler toward the end of one branch line for piping associated with preaction, and dry pipe systems to perform a visual inspection in accordance with NFPA 25 (2011 Edition) Section 14.2.1. • Revise Fire Water System Program procedures to inspect the normally dry fire suppression piping and piping components with a 10 CFR 54.4(a)(3) intended function that may be wetted to ensure that the piping does not collect water. In the event areas are identified that collect water, perform the following augmented tests and inspections to ensure that flow blockage have not occurred. 1. In each 5-year interval beginning with the 5-year period before the period of extended operation, perform either (a) a flow test or flush sufficient to detect potential flow blockage, or (b) visual inspections on 100 percent of the internal surface of piping segments that allow water			

	to collect. 2. In each 5-year interval during the period of extended operation, perform volumetric wall thickness inspections on 20 percent of the length of piping segments that allow water to collect. Data points are obtained to the extent that potential degraded condtions can be identified (e.g., general corrosion, MIC). The 20 percent of piping inspected in each 5-year interval should be in different locations than piping inspected in previous intervals. If the results of a 100 percent interval visual inspection are acceptable and the segment is not subsequently wetted, no futher augmented tests or inspections are necessary. • Revise Fire Water System Program procedures to include inspecting sprinklers in the overhead from the floor for signs of corrosion. • Revise Fire Water System Program procedure to include periodic inspection of hose reels for degradation. • Revise Fire Water System Program procedures to replace sprinklers that the tested sprinkler represents, if the tested sprinkler fails to meet the test acceptance criteria. • Revise Fire Water System Program procedures to ensure the hydrant valve is opened fully and ensure the hydrant flows for not less than one minute during flow testing. • Revise Fire Water System Program procedures for inspecting the interior of the fire water tanks to include the following. 1. A Review of at least two previous coating inspection results is performed prior to conducting a coating inspection. 2. The coating inspection report will include a list of locations identified with coating degradaton including, where possible,			

	photograghs indexed to inspection location, and a prioritization of the repair areas into areas that must be repaired before returning the system to service and areas where coating repair can be postponed to a subsequent inspection or repair opportunity. • Revise Fire Water System Program procedures for inspecting the interior of the fire water tanks at the frequency specified by NFPA 25 Section 9.2.6 to include the following. 1. Testing for possible voids beneath the tank. 2. Inspection of the vortex breaker. 3. Coating inspections and documentation, and review of inspection results are performed by qualified personnel. ▪ Individuals performing coating inspections are certified to ANSI N45.2.6, “Qualifications of Inspection, Examination, and Testing Personnel for Nuclear Power Plants.” ▪ A nuclear coatings specialist qualified in accordance with ASTM D 7108-05, “Standard Guide for Establishing Qualifications for a Nuclear Coatings Specialist,” will evaluate inspection findings and prepare post-inspection reports. • Revise Fire Water System Program procedures to determine the extent of coating defects on the interior of the fire water tanks by using one or more of the following methods when conditions such as cracking, peeling, blistering, delamination, rust or flaking are identified during visual examination. 1. Adhesion testing endorsed by Regulatory Guide 1.54. 2. Dry film thickness measurements at random locations to determine overall coating thickness as specificed in NFPA 25 (2011			

	Edition) Section 9.2.7 Item (2). 3. Nondestructive ultrasonic readings to evaluate the wall thickness where there is evidence of pitting or corrosion as specified in NFPA 25 (2011 Edition) Section 9.2.7 Item (3). 4. Spot wet-sponge tests to detect pinholes, cracks, or other compromises in the coating as specified in NFPA 25 (2011 Edition) Section 9.2.7 Item (4). 5. Test the tank bottom for metal loss or rust on the underside by use of ultrasonic testing where there is evidence of pitting or corrosion as specified in NFPA 25 (2011 Edition) Section 9.2.7 Item (5). • Revise Fire Water System Program procedures to determine the extent of coating defects on the interior of the fire water tanks by using one or more of the following methods when conditions such as cracking, peeling, blistering, delamination, rust or flaking are identified during visual examination in accordance with NFPA 25 (2011), Section 9.2.6.4. 1. Lightly tapping and scraping the coating to determine the coating integrity. 2. Dry film thickness measurements at random locations to determine overall thickness of the coating. 3. Wet-sponge testing or dry film testing to identify holidays in the coating. 4. Adhesion testing in accordance with ASTM D3359, ASTM D4541, or equivalent testing endorsed by RG 1.54 at a minimum of three locations. 5. Ultrasonic testing where there is evidence of pitting or corrosion to determine if the tank thickness meets the minimum thickness criteria. • Revise the Fire Water System Program procedures to ensure a fire water tank is not returned to service after identifying interior			

	coating blistering, delamination or peeling unless there are only a few small intact blisters surrounded by coating bonded to the substrate as determined by a qualified coating specialist, or the following actions are performed. 1. Any blistering in excess of a few small intact blisters, or blistering not completely surrounded by coating bonded to the substrate is removed, 2. Any delaminated or peeled coating is removed, 3. The exposed underlying coating is verified to be securely bonded to the substrate as determined by an adhesion test endorsed by RG 1.54 at a minimum of three locations, 4. The outermost coating is feathered and the remaining outermost coating is determined to be securely bonded to the coating below via an adhesion test endorsed by Reg. Guide 1.54 at a minimum of three locations adjacent to the defective area, 5. Ultrasonic testing is performed where there is evidence of pitting or corrosion to ensure the tank meets minimum wall thickness requirements, 6. An evaluation is performed to ensure downstream flow blockage is not a concern, and 7. A follow-up inspection is scheduled to be performed within two years and every two years after that until the coating is repaired, replaced, or removed. • Revise the Fire Water System Program procedures to include the following acceptance criteria for loss of coating integrity. a) Indications of peeling and delamination are not acceptable. b) Blisters are evaluated by a coating specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 including staff limitations associated with use of a particular standard. Blisters should be limited to a few intact			

	small blisters that are completely surrounded by sound coating/lining bonded to the substrate. Blister size and frequency should not be increasing between inspections (e.g., reference ASTM D714-02, “Standard Test Method for Evaluating Degree of Blistering of Paints”). c) Indications such as cracking, flaking, and rusting are to be evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 including staff limitations associated with the use of a particular standard. d) Minor cracking and spalling of cementitious coatings/linings is acceptable provided there is no evidence that the coating/lining is debonding from the base material. e) As applicable, wall thickness measurements, projected to the next inspection, meet design minimum wall requirements. f) Adhesion testing results, when conducted, meet or exceed the degree of adhesion recommended in plant-specific design requirements specific to the coating/lining and substrate. • Revise Fire Water System Program procedures to include a visual inspection of a representative number of locations on the interior surface of below grade fire protection piping at a frequency of at least once every 10 years during the period of extended operation. A representative number is 20% of the population (defined as locations having the same material, environment, and aging effect combination) with a maximum of 25 locations. • Revise Fire Water System Program procedures to inspect the strainers upstream of the deluge valves every three years. • Revise Fire Water System Program procedures			

	for flow testing, main drain testing, or internal inspection to specify an acceptance criterion of no debris observed (i.e., no corrosion products that are sufficient to obstruct flow or cause downstream components to become clogged.) • Revise Fire Water System Program procedures to require an obstruction evaluation if any signs of abnormal corrosion or blockage are identified during flow testing, main drain testing, or internal inspection. Any signs of corrosion or blockage should be removed, its source determined and corrected, and the condition entered into the Corrective Action Program. Where corrosion or blockage is found, the obstruction evaluation should consider system valves, risers, cross mains and branch lines, and the performance of a complete flushing program by qualified personnel. • Revise Fire Water System Program procedures to require an obstruction evaluation in the event there is frequent false tripping of the dry pipe fire suppression system associated with the auxiliary building railroad access.			
13	Enhance the Flow-Accelerated Corrosion Program to revise program documentation to specify that downstream components are monitored closely to mitigate any increased wear when susceptible upstream components are replaced with resistant materials, such as high Cr material.	B.1.22	Prior to May 1, 2024	GNRO-2011/00093
14	Enhance the Inservice Inspection - IWF Program to address inspections of accessible sliding surfaces. Enhance the Inservice Inspection - IWF Program to; clarify that parameters monitored or inspected will include corrosion; deformation; misalignment of supports; missing, detached, or loosened support items; improper clearances of guides and stops; and improper hot or cold settings of spring supports and constant load supports. Accessible areas of sliding surfaces will be monitored for debris, dirt, or indications of excessive loss of material due to wear that could prevent or restrict sliding as intended in the design basis of the support. Structural bolts will be monitored for corrosion and loss of integrity of bolted connections due to self-loosening and	B.1.24	Prior to May 1, 2024	GNRO-2011/00093 GNRO-2012/00105

	material conditions that can affect structural integrity. High-strength structural bolting (actual measured yield strength greater than or equal to 150 ksi or 1,034 MPa in sizes greater than 1 inch nominal diameter) susceptible to stress corrosion cracking (SCC) will be monitored for SCC. When a component support is found with minor age-related degradation, but still is evaluated as "acceptable for continued service" as defined in IWF-3400, the program owner may choose to repair the degraded component and substitute a randomly selected component that is more representative of the general population for it in subsequent inspections. Enhance the Inservice Inspection - IWF Program to clarify that detection of aging effects will include: a) Monitoring structural bolting (American Society for Testing Materials (ASTM) A-325, ASTM F1852, and ASTM A490 bolts) and anchor bolts for loss of material, loose or missing nuts, loss of pre-load and cracking of concrete around the anchor bolts. b) Volumetric examination comparable to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1 for high strength structural bolting to detect cracking in addition to the VT-3 examination. This volumetric examination may be waived with adequate plant-specific justification. c) Identification of all component supports that contain high strength bolting (actual measured yield greater than or equal to 150 ksi) in sizes greater than 1 inch nominal diameter. The extent of examination for support types that contain high-strength bolting will be as specified in ASME Code Section XI, Table IWF-2500-1. GGNS will examine high-strength structural bolting on the frequency specified in ASME Code Section XI, Table IWF-2500-1. Enhance the Inservice Inspection - IWF Program acceptance criteria to include the following as unacceptable conditions. a) Loss of material due to corrosion or wear, which reduces the load bearing capacity of			GNRO-2012/00114 GNRO-2012/00055 GNRO-2012/00114

	the component support; b) Debris, dirt, or excessive wear that could prevent or restrict sliding of the sliding surfaces as intended in the design basis of the support; and c) Cracked or sheared bolts, including high strength bolts, and anchors. Enhance the Inservice Inspection - IWF Program preventive action to include the following. Incorporate into plant procedures recommendations delineated in NUREG-1339, and Electric Power Research Institute (EPRI) NP-5769 and TR-104213 for high-strength structural bolting. These recommendations should address proper selection of bolting material, proper installation torque or tension, and the use of appropriate lubricants and sealants.			GNRO-2011/00093 GNRO-2012/00114
15	Enhance the Inspection of Overhead Heavy Load and Light Load Handling Systems Program to include monitoring of rails in the rail system for the aging effect "wear", and structural connections/bolting for loose or missing bolts, nuts, pins or rivets. Additionally, the program will be clarified to include visual inspection of structural components and structural bolts for loss of material due to various mechanisms and structural bolting for loss of preload due to self-loosening. Enhance the Inspection of Overhead Heavy Load and Light Load Handling Systems Program acceptance criteria to state that any significant loss of material for structural components and structural bolts, and significant wear of rails in the rail system, is evaluated according to ASME B30.2 or other applicable industry standard in the ASME B30 series.	B.1.25	Prior to May 1, 2024	GNRO-2011/00093
16	Implement the Internal Surfaces in Miscellaneous Piping and Ducting Components Program as described in LRA Section B.1.26.	B.1.26	Prior to May 1, 2024	GNRO-2011/00093
17	Enhance the Masonry Wall Program to clarify that parameters monitored or inspected will include monitoring gaps between the supports and masonry walls that could potentially affect wall qualification.	B.1.27	Prior to May 1, 2024	GNRO-2011/00093

	Enhance the Masonry Wall Program to clarify that detection of aging effects require masonry walls to be inspected every 5 years.			
18	Implement the Non-EQ Cable Connections Program as described in LRA Section B.1.28	B.1.28	Prior to May 1, 2024 or the end of the last refueling outage prior to November 1, 2024, whichever is later.	GNRO-2011/00093
19	Enhance the Non environmentally Qualified (Non-EQ) Inaccessible Power Cables (400V to 35kV) Program to include low-voltage (400V to 2kV) power cables. Enhance the Non-EQ Inaccessible Power Cables (400V to 35kV) Program to include condition-based inspections of manholes not automatically dewatered by a sump pump being performed following periods of heavy rain or potentially high water table conditions, as indicated by river level. Enhance the Non-EQ Inaccessible Power Cables (400V to 35kV) Program to clarify that the inspections will include direct observation that cables are not wetted or submerged, that cables/splices and cable support structures are intact, and that dewatering/drainage systems (i.e., sump pumps) and associated alarms if applicable operate properly.	B.1.29	Prior to May 1, 2024 or the end of the last refueling outage prior to November 1, 2024, whichever is later.	GNRO-2011/00093
20	Implement the Non-EQ Instrumentation Circuits Test Review Program as described in LRA Section B.1.30.	B.1.30	Prior to May 1, 2024 or the end of the last refueling outage prior to November 1, 2024, whichever is later.	GNRO-2011/00093
21	Implement the Non-EQ Insulated Cables and Connections Program as described in LRA Section B.1.31.	B.1.31	Prior to May 1, 2024 or the end of the last refueling outage prior to November 1, 2024, whichever is later.	GNRO-2011/00093
22	Enhance the Oil Analysis Program to provide a formalized analysis technique for particulate counting. Enhance the Oil Analysis Program to include piping and components within the main generator system (N41) with an internal environment of lube oil.	B.1.32	Prior to May 1, 2024	GNRO-2011/00093

Item Number	Commitment	LRA Section	Implementation Schedule	Source
23	Implement the One-Time Inspection Program as described in LRA Section B.1.33.	B.1.33	Within the 10 years prior to November 1, 2024	GNRO-2011/00093
24	Implement the One-Time Inspection – Small Bore Piping Program as described in LRA Section B.1.34.	B.1.34	Within the 6 years prior to November 1, 2024	GNRO-2011/00093
25	Enhance the Periodic Surveillance and Preventive Maintenance Program to revise program guidance documents as necessary to include all activities as described in LRA Section B.1.35	B.1.35	Prior to May 1, 2024 or the end of the last refueling outage prior to November 1, 2024, whichever is later.	GNRO-2013/00096 GNRO-2014/00076
26	Enhance the Protective Coating Program to include parameters monitored or inspected by the program per the guidance provided in ASTM D5163-08. Enhance the Protective Coating Monitoring and Maintenance Program to provide for inspection of coatings near sumps or screens associated with the Emergency Core Cooling System. Enhance the Protective Coating Program to include acceptance criteria per ASTM D 5163-08.	B.1.36	Prior to May 1, 2024	GNRO-2011/00093
27	Ensure that the additional requirements of the ISP(E) specified in BWRVIP-86, Revision 1, including the conditions of the final NRC safety evaluation for BWRVIP-116 incorporated in BWRVIP-86, Revision 1 will be addressed before the period of extended operation. Ensure that new fluence projections through the period of extended operation and the latest vessel beltline ART Tables are provided to the BWRVIP prior to the period of extended operation.	B.1.38	Prior to May 1, 2024	GNRO-2011/00093 GNRO-2012/00081 GNRO-2012/00081
28	Enhance the Regulatory Guide (RG) 1.127, Inspection of Water-Control Structures Associated With Nuclear Power Plant Program to clarify that detection of aging effects will monitor accessible structures on a frequency not to exceed 5 years consistent with the frequency for implementing the requirements of RG 1.127.	B.1.39	Prior to May 1, 2024	GNRO-2011/00093

Item Number	Commitment	LRA Section	Implementation Schedule	Source
	Enhance the RG 1.127, Inspection of Water-Control Structures Associated With Nuclear Power Plant Program to perform periodic sampling, testing, and analysis of ground water chemistry for pH, chlorides, and sulfates on a frequency of at least every 5 years. Enhance the RG 1.127, Inspection of Water-Control Structures Associated With Nuclear Power Plant Program acceptance criteria to include quantitative acceptance criteria for evaluation and acceptance based on the guidance provided in ACI 349.3R.			
29	Implement the Selective Leaching Program as described in LRA Section B.1.40.	B.1.40	Prior to May 1, 2024 or the end of the last refueling outage prior to November 1, 2024, whichever is later.	GNRO-2011/00093
30	Enhance the Structures Monitoring Program to clarify that the scope includes the following: a) In-scope structures and structural components. • Containment Building (GGN 2) • Control House – Switchyard • Culvert No. 1 and drainage channel • Manholes and Ductbanks • Radioactive Waste Building Pipe Tunnel • Auxiliary Building (GGN2) • Turbine Building (GGN2) b) In-scope structural components • Anchor bolts • Anchorage / embedments • Base plates • Basin debris screen and grating • Battery racks • Beams, columns, floor slabs and interior walls • Cable tray and cable tray supports	B.1.42	Prior to May 1, 2024	GNRO-2011/00093 GNRO-2012/00074 GNRO-2012-00095

Item Number	Commitment	LRA Section	Implementation Schedule	Source
	• Component and piping supports • Conduit and conduit supports • Containment sump liner and penetrations • Containment sump structures • Control room ceiling support system • Cooling tower drift eliminators • Cooling tower fill • CST/RWST retaining basin (wall) • Diesel fuel tank access tunnel slab • Drainage channel • Drywell electrical penetration sleeves • Drywell equipment hatch • Drywell floor slab (concrete) • Drywell head • Drywell head access manway • Drywell liner plate • Drywell mechanical penetration sleeves • Drywell personnel access lock • Drywell wall (concrete) • Ductbanks • Electrical and instrument panels and enclosures • Equipment pads/foundations • Exterior walls • Fan stack grating • Fire proofing • Flood curbs • Flood retention materials (spare parts) • Flood, pressure and specialty doors • Floor slab • Foundations • HVAC duct supports • Instrument line supports • Instrument racks, frames and tubing trays • Interior walls • Main steam pipe tunnel • Manholes • Manways, hatches, manhole covers, and hatch covers • Metal siding • Missile shields • Monorails • Penetration sealant (flood, radiation) • Penetration sleeves (mechanical/ electrical			

Item Number	Commitment	LRA Section	Implementation Schedule	Source
	not penetrating primary containment boundary) • Pipe whip restraints • Pressure relief panels • Reactor pedestal • Reactor shield wall (steel portion) • Roof decking • Roof hatches • Roof membrane • Roof slabs • RPV pedestal sump liner and penetrations • Seals and gaskets (doors, manways and hatches) • Seismic isolation joint • Stairway, handrail, platform, grating, decking, and ladders • Structural bolting • Structural steel, beams columns, and plates • Sumps and Sump liners • Support members: welds; bolted connections; support anchorages to building structure • Support pedestals • Transmission towers (see Note 1) • Upper containment pool floor and walls • Vents and louvers • Weir wall liner plate Note 1: The inspections of these structures may be performed by the transmission personnel. However, the results of the inspections will be provided to the GGNS Structures Monitoring Program owner for review. c) Clarify the term “significant degradation” to include “that could lead to loss of structural integrity”. d) Include guidance to perform periodic sampling, testing, and analysis of ground water chemistry for pH, chlorides, and sulfates on a frequency of at least every 5 years. Enhance the Structures Monitoring Program to clarify that parameters monitored or inspected include:			

Item Number	Commitment	LRA Section	Implementation Schedule	Source
	a) inspection for missing nuts for structural connections. b) monitoring sliding/bearing surfaces such as Lubrite plates for loss of material due to wear or corrosion, debris, or dirt. The program will be enhanced to include monitoring elastomeric vibration isolators and structural sealants for cracking, loss of material, and hardening. c) Include periodically inspecting the leak chase system associated with the upper containment pool and spent fuel pool to ensure the tell-tales are free of significant blockage. The inspection will also inspect concrete surfaces for degradation where leakage has been observed, in accordance with this Program.			
	Enhance the Structures Monitoring Program to clarify that detection of aging effects will: a) include augmented inspections of vibration isolators by feel or touch to detect hardening if the vibration isolation function is suspect. b) Require inspections every 5 years for structures and structural components within the scope of license renewal.			GNRO-2012/00054
	c) Require direct visual examinations when access is sufficient for the eye to be within 24-inches of the surface to be examined and at an angle of not less than 30° to the surface. Mirrors may be used to improve the angle of vision and accessibility in constricted areas.			GNRO-2011/00093
	d) Specify that remote visual examination may be substituted for direct examination. For all remote visual examinations, optical aids such as telescopes, borescopes, fiber optics, cameras, or other suitable instruments may be used provided such systems have a resolution capability at least equivalent to that attainable by direct visual examination.			GNRO-2012/00098 GNRO-2012/00054
	e) Include instructions to augment the visual examinations of roof membranes, and seals			

Item Number	Commitment	LRA Section	Implementation Schedule	Source
	and gaskets (doors, manways, and hatches) with physical manipulation of at least 10 percent of available surface area. Enhance the Structures Monitoring Program acceptance criteria by prescribing acceptance criteria based on information provided in industry codes, standards, and guidelines including NEI 96-03, ACI 201.1R-92, ANSI/ASCE 11-99 and ACI 349.3R-96. Industry and plant-specific operating experience will also be considered in the development of the acceptance criteria.			GNRO-2012/00054 GNRO-2012/00076 GNRO-2011/00093
31	Enhance the Water Chemistry Control – Closed Treated Water Program to provide a corrosion inhibitor for the engine jacket water on the engine-driven fire water pump diesel in accordance with industry guidelines and vendor recommendations. Enhance the Water Chemistry Control – Closed Treated Water Program to provide periodic flushing of the engine jacket water and cleaning of heat exchanger tubes for the engine-driven fire water pump diesel in accordance with industry guidelines and vendor recommendations. Enhance the Water Chemistry Control – Closed Treated Water Program to provide testing of the engine jacket water for the engine-driven fire water pump diesels at least annually. Enhance the Water Chemistry Control – Closed Treated Water Program to revise the water chemistry procedure for closed treated water systems to align the water chemistry control parameter limits with those of EPRI 1007820.	B.1.44	Prior to May 1, 2024	GNRO-2011/00093 GNRO-2012/00049

Item Number	Commitment	LRA Section	Implementation Schedule	Source
	Enhance the Water Chemistry Control –e • Drywell chilled water (DCW – system P72) • Plant chilled water (PCW – system P71) • Diesel generator cooling water subsystem for Division I and II standby diesel generators • Diesel engine jacket water for engine-driven fire water pump • Diesel generator cooling water subsystem for Division III (HPCS) diesel generator • Turbine building cooling water (TBCW– system P43) • Component cooling water (CCW – system P42) These inspections will be conducted in accordance with applicable ASME Code requirements, industry standards, and other plant-specific inspection and personnel qualification procedures that are capable of detecting corrosion or cracking. Enhance the Water Chemistry Control – Closed Treated Water Program to inspect a representative sample of piping and components at a frequency of once every ten years for the following systems. • Drywell chilled water (DCW – P72) • Plant chilled water (PCW – P71) • Diesel generator cooling water subsystem for Division I and II standby diesel generators • Diesel engine jacket water for engine-driven fire water pump • Diesel generator cooling water subsystem for Division III (HPCS) diesel generator • Turbine building cooling water (TBCW – P43) • Component cooling water (CCW – P42) Components inspected will be those with the highest likelihood of corrosion or cracking. A representative sample is 20% of the population (defined as components having the same material, environment, and aging effect combination) with a			

Item Number	Commitment	LRA Section	Implementation Schedule	Source
	maximum of 25 components. The inspection methods will be in accordance with applicable ASME Code requirements, industry standards, or other plant specific inspection and personnel qualification procedures that ensure the capability of detecting corrosion or cracking.			
32	Enhance the BWR CRD Return Line Nozzle Program to include inspection of the CRD return line nozzle inconel end cap to carbon steel safe end dissimilar metal weld once prior to the period of extended operation and every 10 years thereafter.	B.1.6	Prior to May 1, 2024 or the end of the last refueling outage prior to November 1, 2024, whichever is later.	GNRO-2012/00029
33	Enhance the BWR Penetrations Program to include that site procedures which implement the guidelines of BWRVIP-47-A will be clarified to indicate that the guidelines of BWRVIP-47-A apply without exceptions.	B.1.8	Prior to May 1, 2024	GNRO-2012/00029
34	Deleted			GNRO-2013/00028
35	The Service Water Integrity Program will be enhanced as follows. During the l0-year period prior to the period of extended operation, visual inspections will be performed of coated internal surfaces of standby service water system components. Subsequent coating inspections will be performed based on inspection results as follows. i. If no peeling, delamination, blisters, or rusting are observed, and any cracking and flaking has been found acceptable, subsequent inspections will be performed at least once every 6 years. If the coating is inspected on one train and no indications are found, and, if the redundant train has the same coating and turbulent flow is not present, then the redundant train need not be inspected during that inspection interval. ii. If the inspection results do not meet (i) and a coating specialist has determined that no remediation is required, then subsequent inspections will be conducted on an every	B.1.41	Within the 10 years prior to November 1, 2024	GNRO-2013/00096 GNRO-2014/00030 GNRO-2014/00076 GNRO-2015/000055

Item Number	Commitment	LRA Section	Implementation Schedule	Source
	other refueling outage interval. iii. If the inspection results do not meet (i) and a coating specialist determines remediation is required, then the coated components can only be returned to service if the following actions are performed (1) any blistering in excess of a few small intact blisters, or blisters not completely surrounded by coating bonded to the substrate is removed, (2) any delaminated or peeled coating is removed, (3) the exposed underlying coating is verified to be securely bonded to the substrate at a minimum of three locations as determine by adhesion testing endorsed by Regulatory Guide (RG) 1.54 adjacent to the defective area, (4) the outer most coating is feathered and the remaining outermost coating is determined to be securely bonded to the coating below via adhesion testing endorsed by RG 1.54, (5) ultrasonic testing is performed to ensure the component meets the minimum wall thickness requirements, (6) an evaluation is performed within two years and every two years until the coating is repaired, replaced or removed.			
	Revise Service Water Integrity Program documents to include inspections for loss of material due to erosion. Revise Service Water Integrity Program documents to include visual inspections for loss of coating Integrity during the 10-year period prior to the period of extended operation. Include provisions to specify subsequent coating inspections based on inspection results as follows. i. If no peeling, delamination, blisters, or rusting are observed, and any cracking and flaking has been found acceptable, subsequent inspections will be performed at least once every 6 years. If the coating is inspected on one train and no indications are found, and the redundant train has the same coating and turbulent flow is not present, then the	B.1.41	Prior to May 1, 2024	GNRO-2013/00096 GNRO-2014/00030 GNRO-2014/00076 GNRO-2015/00055

Item Number	Commitment	LRA Section	Implementation Schedule	Source
	redundant train need not be inspected during that inspection interval. ii. If the inspection results do not meet (i) and a coating specialist has determined that no remediation is required, then subsequent inspections will be conducted on an every other refueling outage interval. iii. If the inspection results do not meet (i) and a coating specialist determines mediation is required, then the coated components can only be returned to service if the following actions are performed (1) any blistering in excess of a few small intact blisters, or blisters not completely surrounded by coating bonded to the substrate is removed, (2) any delaminated or peeled coating is removed, (3) the exposed underlying coating is verified to be securely bonded to the substrate at a minimum of three locations as determine by adhesion testing endorsed by Regulatory Guide (RG) 1.54 adjacent to the defective area, (4) the outer most coating is feathered and the remaining outermost coating is determined to be securely bonded to the coating below via adhesion testing endorsed by RG 1.54, (5) ultrasonic testing is performed to ensure the component meets the minimum wall thickness requirements, (6) an evaluation is performed within two years and every two years until the coating is repaired, replaced or removed. Revise Service Water Integrity Program procedures for inspecting the interior of coated components to include one or more of the following methods to determine the condition of the coating and the condition of the component under the degraded coating when conditions such as cracking, peeling, blisters, delamination, rust or flaking are identified during the visual examination. 1. Lightly tapping and scraping the coating to determine the coating integrity.			

Item Number	Commitment	LRA Section	Implementation Schedule	Source
	2. Wet-sponge testing or dry film testing to identify holidays in the coating. 3. Adhesion testing in accordance with ASTM D3359, ASTM D4541, or equivalent testing endorsed by RG 1.54 at a minimum of three locations adjacent to the defective area. 4. Ultrasonic testing to determine if the component's wall thickness meets the minimum thickness criteria. Revise Service Water Integrity Program documents to visually inspect 50 percent of coated internal surfaces of piping or a minimum of 73 locations of 360 degrees of one linear foot for each combination of type of coating, material the coating is protecting, and environment. Inspection locations will be based on coating degradation susceptibility, operating experience, vendor recommendation and safety significance. Inspect all accessible coated internal surfaces of tanks. Revise Service Water Integrity Program documents to include the following coating integrity acceptance criteria: (1) peeling and delamination are not acceptable, (2) cracking is not acceptable if accompanied by delamination or loss of adhesion, and (3) blisters are limited to a few small intact blisters that are completely surrounded by sound coating bonded to the surface. Revise Service Water Integrity Program documents to include the following coating integrity corrective actions: In the event peeling, delamination, cracking, or loss of adhesion is identified, follow-up evaluations including adhesion testing endorsed by RG 1.54 will be performed. In the event the base metal is exposed and the visual inspection identifies corrosion, this inspection finding will be entered into the Corrective Action Program, and an evaluation will confirm the component remains acceptable for continued service. As necessary, a volumetric examination will be performed to ensure there is sufficient wall thickness so that the component remains capable of performing its intended function. If repair or replacement of the coating is postponed, the			

Item Number	Commitment	LRA Section	Implementation Schedule	Source
	evaluation will consider the minimum wall thickness requirements and the rate of corrosion and confirm the component remains acceptable for continued service until the next inspection or repair opportunity, which will be within two years. Revise Service Water Integrity Program documents to specify a review of at least the two previous coating inspection results prior to conducting a coating inspection. Revise Service Water Integrity Program procedures to ensure coating inspections are performed by individuals certified to ANSI N45.2.6, “Qualifications of Inspection, Examination, and Testing Personnel for Nuclear Power Plants.” Revise Service Water Integrity Program procedures to ensure that a nuclear coatings specialist qualified in accordance with ASTM D 7108-05, “Standard Guide for Establishing Qualifications for a Nuclear Coatings Specialist,” will evaluate inspection finding and prepare post-inspection reports. Revise Service Water Integrity Program documents to state that coating inspection reports will include lists of locations identified with coating deterioration including, where possible, photographs indexed to inspection location, and a prioritization of the repair areas into areas that must be repaired before returning the system to service and areas where coating repair can be postponed to the next inspection or repair opportunity~~.~~, which will be within two years. Revise Service Water Integrity Program procedures to ensure degraded coating/lining will be evaluated for potential flow blockage downstream prior to returning a coated component to service. Any coating that is found degraded and returned to service prior to repair or replacement will be evaluated by a coating specialist qualified in accordance with ASTM International standards endorsed by RG 1.54. The evaluation considers the effect of the coating/lining failure on the component’s intended function, problems identified			

Item Number	Commitment	LRA Section	Implementation Schedule	Source
	during prior inspections, repair methods used during prior repairs and known service history of the original coating.			
36	Revise program documentation to specify that components subject to wall-thinning mechanisms other than FAC, which are replaced with alternate materials (e.g., replacing a carbon steel pipe with stainless steel) shall continue to be periodically monitored at a frequency commensurate with their post-replacement wear rate and operating time.	B.1.22	Prior to May 1, 2024	GNRO-2013/00096