APPENDIX A

LICENSE RENEWAL

A.1 INTRODUCTION

This appendix provides the information submitted in an Updated Final Safety Analysis Report Supplement as required by 10 CFR 54.21(d) for the Indian Point Energy Center (IPEC) License Renewal Application (LRA). The LRA contains the technical information required by 10 CFR 54.21(a) and (c). Appendix B of the IPEC LRA provides descriptions of the programs and activities that manage the effects of aging for the period of extended operation. Section 4 of the LRA documents the evaluations of time-limited aging analyses for the period of extended operation. Appendix B and Section 4 have been used to prepare the program and activity descriptions for both IP2 and IP3 Updated Final Safety Analysis Reports (UFSAR) Supplement information in this appendix.

With inclusion of the UFSAR Supplement in the UFSAR, future changes to the descriptions of the programs and activities will be made in accordance with 10 CFR 50.59.

A.2 NEW UFSAR SECTION FOR UNIT 3

The following information will be integrated into the UFSAR to document aging management programs and activities credited in the license renewal review and time-limited aging analyses evaluated for the period of extended operation. References to other sections are to UFSAR sections, not to sections in the LRA.

A.2.0 Supplement for Renewed Operating License

The Indian Point Energy Center license renewal application (Reference A.2-1) 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.2-2). 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.2.1) and a description of the evaluation of time-limited aging analyses for the period of extended operation (Section A.2.2). The period of extended operation is the 20 years after the expiration date of the original operating license.

A.2.1 Aging Management Programs and Activities

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) through the period of extended operation. This section describes the aging management programs and activities required during the period of extended operation. All aging management programs will be implemented prior to entering the period of extended operation unless otherwise noted.

IPEC 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 Entergy 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 per the existing IPEC corrective action program and document control program and are applicable to all aging management programs and activities that will be required during the period of extended operation. The confirmation process is part of the corrective action program and includes reviews to assure that proposed actions are adequate, 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 Entergy (10 CFR Part 50, Appendix B) Quality Assurance Program are applicable to all aging management programs and activities required 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 IPEC. 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 IPEC that indicates a condition adverse to quality or a non-conformance.

A.2.1.1 Aboveground Steel Tanks Program

The Aboveground Steel Tanks Program manages loss of material on outdoor tanks situated on soil or concrete. The program includes preventive measures 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 sealants. 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 is 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 Aboveground Steel Tanks Program will be enhanced to include the following 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 (OD)[4, 5]				
Steel	Treated water	Loss of material	Volumetric from OS[6] or visual from IS	One time prior to December 31, 2019[7]
Stainless Steel	Treated water	Loss of material	Volumetric from OS[6] or visual from IS	One time prior to December 31, 2019[7]
Inspections to identify degradation of external surfaces of tank roof, tank shell, and bottom not exposed to soil or concrete[8]				
Steel	Air-indoor uncontrolled Air-outdoor	Loss of material	Visual from OS	Each refueling outage interval
Stainless Steel	Air-outdoor	Loss of material	Visual from OS	Each refueling outage interval
		Cracking	Surface[9, 10]	Each 10-year period of the period of extended operation[11]
Inspections to identify degradation of tank bottoms and tank shells exposed to soil or concrete				
Steel	Soil or concrete	Loss of material	Volumetric from IS	Each 10-year period of the period of extended operation[11]
Stainless Steel	Soil or concrete	Loss of material	Volumetric from IS	Each 10-year period of the period of extended operation[11]

Tank Inspection Table Notes

1. IPEC LRA Section B.1.9, “Diesel Fuel Monitoring,” manages loss of material on the internal surfaces of fuel oil storage tanks.

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 effective at detecting the 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, the low-frequency electromagnetic technique (LFET) can be used to scan an entire surface of a tank. An LFET inspection can effectively detect loss of material in the tank shell, roof, or bottom if follow-up ultrasonic examinations are conducted in any areas where the wall thickness is below nominal.

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.

4. Visual inspections to identify degradation of the inside surfaces of tank shell, roof, and bottom should cover all the inside surfaces.

5. Materials, if any, accumulated on the tank bottom (e.g., sediment, silt) are removed to allow for complete internal inspections of the tank’s surfaces.

6. At least 25 percent of the tank surface is inspected using a method capable of precisely determining wall thickness. The inspection method should be demonstrated capable of detecting both general and pitting corrosion.

7. At least one tank for each material and environment combination should be inspected.

8. For tanks with tightly adhering insulation without evidence of damage to the moisture barrier, inspections may consist of examination of the exterior surface of the insulation for indications of damage to the jacketing of protective outer layer of the insulation. For tanks with caulking or sealant at the concrete to tank interface, visual inspection of the caulking or sealant is performed in conjunction with physical manipulation of the caulking or sealant.

9. An inspection will be performed prior to December 31, 2019. Subsequent inspections are not required if an evaluation conducted prior to December 31, 2019 and at the scheduled time of each subsequent inspection during the PEO demonstrates the absence of chlorides or other deleterious compounds at sufficient levels to cause pitting corrosion, crevice corrosion, or cracking. 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 tank.

10. A minimum of either 25 sections of the tank’s surface (e.g., 1-square-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 (i.e., areas where contaminants could collect, inlet and outlet nozzles, welds).

11. The first inspection will be performed during the first 10 years of the period of extended operation. Subsequent inspections are not required if evaluations conducted at the time of the first inspection and at the scheduled time of each subsequent inspection during the PEO demonstrate 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 corrosivity. The evaluation should include soil sampling from underneath the tank.

Enhancements will be implemented prior to December 31, 2019.

A.2.1.2 Bolting Integrity Program

The Bolting Integrity Program is an existing program that relies on recommendations for a comprehensive bolting integrity program, as delineated in NUREG-1339, industry recommendations, and Electric Power Research Institute (EPRI) NP-5769, with the exceptions noted in NUREG-1339 for safety-related bolting. The program relies on industry recommendations for comprehensive bolting maintenance, as delineated in EPRI TR-104213 for pressure retaining bolting and structural bolting.

The program applies to bolting and torquing practices of safety- and nonsafety-related bolting for pressure retaining components, NSSS component supports, and structural joints. The program addresses all bolting regardless of size except reactor head closure studs, which are addressed by the Reactor Head Closure Studs Program. The program includes periodic inspection of closure bolting for signs of leakage that may be due to crack initiation, loss of preload, or loss of material due to corrosion. The program also includes preventive measures to preclude or minimize loss of preload and cracking.

The Bolting Integrity Program will be enhanced to include the following.

- Revise applicable procedures to clarify that actual yield strength is used in selecting materials for low susceptibility to SCC and to clarify the prohibition on use of lubricants containing MoS_2 for bolting.

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

A.2.1.3 Boral Surveillance Program

The Boral Surveillance Program is an existing program that provides assurance the Boral neutron absorbers in the spent fuel racks maintain the validity of the criticality analysis in support of the rack design. The program relies on representative coupon samples mounted in surveillance assemblies located in the spent fuel pool to monitor performance of the absorber material without disrupting the integrity of the storage system.

Surveillance assemblies are removed from the spent fuel pool on a prescribed schedule and physical and chemical properties are measured. From this data, the stability and integrity of the Boral in the storage cells are assessed.

Boral inspection and testing activities are conducted at a frequency of at least once every 10 years.

A.2.1.4 Boric Acid Corrosion Prevention Program

The Boric Acid Corrosion Prevention Program is an existing program that relies on implementation of recommendations of NRC Generic Letter 88-05 to monitor the condition of

components on which borated reactor water may leak. The program detects boric acid leakage by periodic visual inspection of systems containing borated water for deposits of boric acid crystals and the presence of moisture; and by inspection of adjacent structures, components, and supports for evidence of leakage. This program manages loss of material and loss of circuit continuity, as applicable. The program includes provisions for evaluation when leakage is discovered by other activities. Program improvements have been made as suggested in NRC Regulatory Issue Summary 2003-013.

A.2.1.5 Buried Piping and Tanks Inspection Program

The Buried Piping and Tanks Inspection Program is a new program that includes (a) preventive measures to mitigate corrosion and (b) inspections to manage the effects of corrosion on the pressure-retaining capability of buried and underground carbon steel, gray cast iron, copper alloy and stainless steel components. Preventive measures are in accordance with standard industry practice for maintaining external coatings and wrappings. Buried components are inspected when excavated during maintenance. If trending within the corrective action program identifies susceptible locations, the areas with a history of corrosion problems are evaluated for the need for additional inspection, alternate coating, or replacement.

Cathodic protection (CP) systems installed at IPEC provide additional protection of license renewal in-scope buried piping and minimize corrosion in areas that have been found susceptible to corrosion based on indirect inspections or testing. To the extent they are proven effective, the CP systems at IPEC will be considered in risk ranking to ensure that the in-scope buried piping systems that are more susceptible to external corrosion continue to receive a higher risk ranking when determining inspection priority.

IP3 will perform 14 direct visual inspections of buried piping during the 10 year period prior the PEO. IP3 will perform 16 direct visual inspections during each 10-year period of the PEO. Soil samples will be taken prior to the PEO and at least once every 10 years into the PEO. Soil will be tested at a minimum of two locations at least three feet below the surface near in-scope piping to determine representative soil conditions for each system. If test results indicate the soil is corrosive then the number of piping inspections will be increased to 22 during each 10-year period of the PEO.

The Buried Piping and Tanks Inspection Program will be implemented prior to the period of extended operation. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M34, Buried Piping and Tanks Inspection with the following modification.

The Buried Piping and Tanks Inspection Program will be modified based on operating experience to include a risk assessment of in-scope buried piping and tanks that includes consideration of the impacts of buried piping or tank leakage and of conditions affecting the risk for corrosion. The program will classify pipe segments and tanks as having a high, medium or low impact of leakage based on the safety class, the hazard posed by fluid contained in the piping and the impact of leakage on reliable plant operation. Corrosion risk will be determined through consideration of piping or tank material, soil resistivity, drainage, the presence of cathodic protection and the type of coating. Inspection priority and frequency for periodic inspections of the in-scope piping and tanks will be based on the results of the risk assessment. Inspections will be performed using qualified inspection techniques with demonstrated effectiveness, Inspections will begin prior to the period of extended operation. Underground

piping within the scope of license renewal and subject to aging management review will be visually inspected prior to the period of extended operation and then on a frequency of at least once every two years during the period of extended operation. This inspection frequency will be maintained unless the piping is subsequently coated in accordance with the preventive actions specified in NUREG-1801 Section XI.M41 as modified by LR-ISG-2011-03. Visual inspections will be supplemented with surface or volumetric non-destructive testing if indications of significant loss of material are observed. Consistent with revised NUREG-1801 Section XI.M41, such adverse indications will be entered into the plant corrective action program for evaluation of extent of condition and for determination of appropriate corrective actions (e.g., increased inspection frequency, repair, replacement).

A.2.1.6 Containment Leak Rate Program

The Containment Leak Rate Program is an existing program. As described in 10 CFR Part 50, Appendix J, containment leak rate tests are required to assure that (a) leakage through reactor containment and systems and components penetrating containment shall not exceed allowable values specified in technical specifications or associated bases and (b) periodic surveillance of reactor containment penetrations and isolation valves is performed so that proper maintenance and repairs are made during the service life of containment, and systems and components penetrating containment.

A.2.1.7 Containment Inservice Inspection (CII) Program

The Containment Inservice Inspection (CII) Program is an existing program encompassing ASME Section XI Subsection IWE and IWL requirements as modified by 10 CFR 50.55a.

Visual inspections for IWE monitor loss of material of the steel containment liner and integral attachments; containment hatches and airlocks; moisture barriers; and pressure-retaining bolting by inspecting surfaces for evidence of flaking, blistering, peeling, discoloration, and other signs of distress.

Visual inspections for IWL monitor structural concrete surfaces for evidence of leaching, erosion, voids, scaling, spalls, corrosion, cracking, exposed reinforcing steel, and detached embedment.

The Containment Inservice Inspection (CII-IWL) Program will be enhanced to include the following.

- Revise applicable procedures to include inspections of containment using enhanced characterization of degradation (i.e., quantifying the dimensions of noted indications through the use of optical aids) during the period of extended operation. The enhancement includes obtaining critical dimensional data of degradation where possible through direct measurement or the use of scaling technologies for photographs, and the use of consistent vantage points for visual inspections.

A.2.1.8 Diesel Fuel Monitoring Program

The Diesel Fuel Monitoring Program is an existing program that entails sampling to ensure that adequate diesel fuel quality is maintained to prevent loss of material and fouling in fuel systems. Exposure to fuel oil contaminants such as water and microbiological organisms is minimized by

periodically draining and cleaning tanks and by verifying the quality of new oil before its introduction into the storage tanks. Sampling and analysis activities are in accordance with technical specifications on fuel oil purity and the guidelines of ASTM Standards D4057-95 and D975-95 (or later revisions of these standards).

Thickness measurements of storage tank bottom surfaces verify that significant degradation is not occurring.

The One-Time Inspection Program describes inspections planned to verify the effectiveness of the Diesel Fuel Monitoring Program.

The Diesel Fuel Monitoring Program will be enhanced to include the following.

- Revise applicable procedures to include cleaning and inspection of the EDG fuel oil day tanks, Appendix R fuel oil storage tank and Appendix R fuel oil day tank once every ten years.
- Revise applicable procedures to include quarterly sampling and analysis of the Appendix R fuel oil storage tank. Particulates (filterable solids), water and sediment checks will be performed on the samples. Filterable solids acceptance criterion will be $\leq$ 10mg/l. Water and sediment acceptance criterion will be $\leq$ 0.05%.
- Revise applicable procedures to include thickness measurement of the bottom surface of the EDG fuel oil day tanks, EDG fuel oil storage tanks, Appendix R fuel oil storage tank, and diesel fire pump fuel oil storage tank once every ten years.
- Revise appropriate procedures to change the Appendix R fuel oil day tank and diesel fire pump fuel oil storage tank analysis for water and particulates to a quarterly frequency.
- Revise applicable procedures to specify acceptance criteria for thickness measurements of the fuel oil storage tanks within the scope of the program.
- Revise applicable procedures to direct samples be taken near the tank bottom and include direction to remove water when detected.
- Revise applicable procedures to direct sampling of the onsite portable fuel oil tanker contents prior to transferring the contents to the storage tanks.
- Revise applicable procedures to direct the addition of chemicals including biocide when the presence of biological activity is confirmed.

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

A.2.1.9 Environmental Qualification (EQ) of Electric Components Program

The EQ of Electric Components Program is an existing program that 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 exceeding their qualification are refurbished, replaced, or their qualification extended prior to reaching the aging

limits established in the evaluations. Some aging evaluations for EQ components are considered time-limited aging analyses (TLAAs) for license renewal.

A.2.1.10 External Surfaces Monitoring Program

The External Surfaces Monitoring Program is an existing program that inspects external surfaces of components subject to aging management review. The program is also credited with managing loss of material from internal surfaces, for situations in which internal and external material and environment combinations are the same such that external surface condition is representative of internal surface condition.

Surfaces that are inaccessible during plant operations are inspected during refueling outages. Periodic representative surface condition inspections of the in-scope mechanical indoor components under insulation (with process fluid temperature below the dew point) and outdoor components under insulation will be performed during each 10-year period of the period of extended operation. Surfaces are inspected at frequencies to assure the effects of aging are managed such that applicable components will perform their intended function during the period of extended operation.

The External Surfaces Monitoring Program will be enhanced to include the following.

- Guidance documents will be revised to require periodic inspections of systems in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4 (a)(1) and (a)(3). Inspections shall include areas surrounding the subject systems to identify hazards to those systems. Inspections of nearby systems that could impact the subject systems will include SSCs that are in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4 (a)(2).

- Procedures will be revised to specify the following for insulated components.

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

    - For a representative sample of insulated indoor components exposed to condensation (because the component is operated below the dew point) and insulated outdoor components, insulation will be removed for visual inspection of component surfaces. 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 that are alternately wet and dry in environments where trace contaminants could be present and for components that operate for long periods of time below the dew point.

Subsequent inspections will consist of 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.
- 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 seams/joints), periodic inspections under the insulation will continue.

- 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 that is impermeable to moisture will be removed to allow for inspection if there is evidence of damage to the moisture barrier. If the moisture barrier is intact, the likelihood of CUI is low for tightly adhering insulation. Components with tightly adhering insulation constitute a separate population from the remainder of in-scope insulated components. The entire population of in-scope accessible component surfaces covered with tightly adhering insulation will be visually inspected for damage to the moisture barrier at the same frequency as inspections of components with other types of insulation. These inspections will not be credited towards the inspection quantities for components with other types of insulation.

Enhancements will be implemented prior to December 31, 2019.

A.2.1.11 Fatigue Monitoring Program

The Fatigue Monitoring Program is an existing program that tracks the number of critical thermal and pressure transients for selected reactor coolant system components. The program ensures the validity of analyses that explicitly analyzed a specified number of fatigue transients by assuring that the actual effective number of transients does not exceed the analyzed number of transients. The program provides for update of the fatigue usage calculations to maintain a CUF of < 1.0 for the period of extended operation. For the locations identified in Section A.2.2.2.3, updated calculations will account for the effects of the reactor water environment. These calculation updates are governed by Entergy’s 10 CFR 50 Appendix B Quality Assurance (QA) program and include design input verification and independent reviews ensuring that valid assumptions, transients, cycles, external loadings, analysis methods, and environmental fatigue life correction factors will be used in the fatigue analyses. The program requires corrective actions including repair or replacement of affected components before fatigue usage calculations determine the CUF exceeds 1.0. Specific corrective actions are implemented in accordance with the IPEC corrective action program. Repair or replacement of the affected component(s), if necessary, will be in accordance with established plant procedures governing repair and replacement activities. These established procedures are governed by Entergy's 10 CFR 50 Appendix B QA program and meet the applicable repair or replacement requirements of the ASME Code Section XI.

The Fatigue Monitoring Program will be enhanced to include the following.

- Revise appropriate procedures to include all the transients identified. Assure all fatigue analysis transients are included with the lowest limiting numbers. Update the number of design transients accumulated to date.

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

A.2.1.12 Fire Protection Program

The Fire Protection Program is an existing program that includes a fire barrier inspection, an RCP oil collection system inspection, and a diesel-driven fire pump inspection. The fire barrier inspection requires periodic visual inspection of fire barrier penetration seals, fire barrier walls, ceilings, and floors, and periodic visual inspection and functional tests of fire rated doors to ensure that their operability is maintained. The diesel-driven fire pump inspection requires that the pump and its driver be periodically tested and inspected to ensure that diesel engine sub-systems including the fuel supply line can perform their intended functions.

The program also includes periodic inspection and testing of the CO_2 fire protection system.

The Fire Protection Program will be enhanced to include the following.

- Revise appropriate procedures to explicitly state that the diesel fire pump engine sub-systems (including the fuel supply line) shall be observed while the pump is running. Acceptance criteria will be revised to verify that the diesel engine does not exhibit signs of degradation while it is running; such as fuel oil, lube oil, coolant, or exhaust gas leakage.

- Revise appropriate procedures to specify that diesel fire pump engine carbon steel exhaust components are inspected for evidence of corrosion or cracking at least once each operating cycle.

- Revise appropriate procedures to visually inspect the cable spreading room, 480V switchgear room, and EDG room CO_2 fire suppression system for signs of degradation, such as corrosion and mechanical damage at least once every six months.

- Revise appropriate procedures to inspect the external surfaces of the RCP oil collection system for loss of material each refueling outage.

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

A.2.1.13 Fire Water System Program

The Fire Water System Program is an existing program that manages water-based fire protection systems that consist of sprinklers, nozzles, fittings, valves, hydrants, hose stations, fire pump casings, water storage tanks, standpipes, piping, and components that are tested in accordance with applicable National Fire Protection Association (NFPA) codes. Such testing assures functionality of systems. To determine if abnormal corrosion has occurred in water-based fire protection systems, periodic flushing, system performance testing and inspections are conducted. Also, many of these systems are normally maintained at required operating

pressure and monitored such that leakage resulting in loss of system pressure is immediately detected and corrective actions initiated.

In addition, visual inspection results that identify excessive accumulation of corrosion products and appreciable localized corrosion (e.g., pitting) beyond a normal oxide layer will be entered into the corrective action program, and a follow-up volumetric wall thickness examination will be performed.

A sample of sprinkler heads required for 10 CFR 50.48 will be inspected using the guidance of NFPA 25 (2011 Edition) Section 5.3.1.1.1, which states, “Where sprinklers have been in service for 50 years, they shall be replaced or representative samples from one or more sample areas shall be tested. This sampling will be repeated every ten years after initial field service testing.

For coated/lined surfaces of fire water storage tanks determined to not meet the acceptance criteria, physical testing is performed where physically possible in conjunction with the visual inspection. The training and qualification of individuals involved in coating/lining inspections of fire water storage tanks are conducted in accordance with ASTM standards endorsed in RG 1.54 including guidance from the staff associated with a particular standard.

The Fire Water System Program will be enhanced to include the following.

- Revise applicable procedures to include inspection of hose reels for corrosion. In addition, revise the acceptance criteria to verify no unacceptable signs of degradation.

- Revise Fire Water System Program procedures to replace or test closed sprinkler heads required for 10 CFR 50.48 in accordance with NFPA 25 (2011 Edition), Section 5.3.1.

- Revise Fire Water System Program applicable procedures to inspect the internal surface of the foam-based fire suppression tanks at least once every 10 years. Acceptance criteria will be enhanced to verify no abnormal corrosion.

- Revise Fire Water System Program procedures to inspect the water distribution piping inside the charcoal filter units for corrosion when the charcoal is replaced. In the event the amount of corrosion exceeds normal surface corrosion, enter the condition into the corrective action program. (Refer to NFPA-25 (2011 Edition), Section 14.2)

- Revise Fire Water System Program procedures to inspect for and require replacement of sprinkler heads (nozzles) if they show signs of corrosion, loading*, leakage, or if the glass bulb heat responsive element is found empty. (Refer to NFPA-25 (2011 Edition), Section 5.2.1.1.)
  * In lieu of replacing a loaded sprinkler head, sprinklers that are loaded with a coating of dust can be cleaned with compressed air or by vacuum provided that the equipment does not touch the sprinkler head.

- Revise Fire Water System Program procedures to inspect the accessible portions of the water distribution piping inside the charcoal filter units for corrosion when the charcoal is sampled. In the event the amount of corrosion exceeds normal surface corrosion, enter the condition into the corrective action program.

- Revise Fire Water System Program procedures to perform main drain testing in accordance with NFPA 25 (2011 Edition), Section 13.2.5, on 20 percent of the testable automatic standpipes with at least one main drain test in each building. (Refer to NFPA-25 (2011 Edition) Sections 6.3.1.5 and 13.2.5)

- Revise Fire Water System Program procedures to inspect the interior and exterior of the fire water storage tanks in accordance with NFPA 25 (2011 Edition), Sections 9.2.5.5, 9.2.6 and 9.2.7, with the exception of NFPA (2011 Edition) Sections 9.2.7.1 and 9.2.7.6. In lieu of testing specified in Section 9.2.7.1, alternate adhesion testing endorsed by Regulatory Guide (RG) 1.54 may be performed. In lieu of testing specified in Section 9.2.7.6, perform ultrasonic thickness checks or mechanical measurements of any identified corroded areas at least once every five years.

- 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. Lightly tapping and scraping the coating to determine the coating integrity.

  2. Wet-sponge testing or drv film testing to identify holidays in the coating.

  3. Adhesion testing in accordance with ASTM 03359. ASTM 04541, or equivalent testing endorsed by RG 1.54 at a minimum of three locations.

  4. 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 inspector. 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 RG 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 Fire Water System Program procedures to inspect and test the deluge system for the boric acid building filter units every two years in accordance with NFPA 25 (2011 Edition), Section 13.4.3.2.2.

- Revise Fire Water System Program procedures to perform an internal inspection of wet fire water system piping conditions every five years, or after an extended shutdown of greater than one year, by opening a flushing connection at the end of one main and by removing a closed sprinkler toward the end of one branch line for the purpose of inspecting the interior for evidence of loss of material and the presence of foreign organic and inorganic material that could result in flow obstructions or blockage of sprinkler heads or nozzles. In the event there are multiple wet pipe systems in a structure, on third will be inspected every five years such that all systems will be inspected during each 15-year period. The procedures will include (1) guidance to perform an evaluation for MIC in the event tubercles or slime are identified, and (2) acceptance criteria that states “no abnormal debris” (i.e., no corrosion products that could impede flow or cause downstream components to become clogged). Corrective actions will specify that any signs of abnormal corrosion or blockage will be removed and the condition will be entered into the corrective action program. Inspection scope will be expanded to include all of the wet pipe sprinkler systems in that building and the source and extent of condition determined and corrected. (Refer to NFPA-25 (2011 Edition), Section 14.2.)

- Revise Fire Water System Program procedures to perform an obstruction evaluation if any of the following conditions exist. (Refer to NFPA-25 (2011 Edition), Section 14.3.1.)

    - There is an excessive discharge of material during routine flow tests.

    - An inspector’s test valve is clogged during routine testing.

    - Foreign materials are identified during internal inspections.

    - Sprinkler heads are found clogged during removal or testing.

    - Pin hole leaks are identified in fire water piping.

    - After an extended shutdown.

    - There is a 50 percent increase in time it takes for water to flow out the inspector test valve after the associated dry valve is tripped when compared to the original acceptance criteria or last test.

- Revise Fire Water System Program procedures to perform a wall thickness evaluation of any areas identified with excessive accumulation of corrosion products or appreciable

localized pitting beyond a normal oxide layer and enter the condition into the corrective action program. (Refer to LR-ISG-2012-02, Section C, iii, (c).)

- Revise Fire Water System Program procedure(s) to test and inspect the water spray system #11 – charcoal filters associated with the containment purge exhaust, primary auxiliary building exhaust system, and containment pressure relief filtration units in accordance NFPA 25 (2011 Edition) Section 13.4.3.2.2, and the associated sub-steps.

- Revise Fire Water System Program procedure(s) to fully open hydrants, flush at least for one minute, flush until the water is clear, and verify the hydrants drainage takes no longer than 60 minutes. Where drainage is longer than 60 minutes, provide procedural steps to address the situation (e.g., unclog the drain or pump out the hydrant). (Refer to NFPA-25 (2011 Edition), Section 7.3.2)

- Revise Fire Water System Program procedure(s) to perform an air test to ensure spray patterns are not affected by plugged nozzles associated with the hydrogen seal oil unit, main boiler feed pump oil reservoir, main lube oil storage, and main lube oil reservoir foam deluge systems. Where plugged nozzles are identified, the procedure(s) should include a requirement to clean and retest. (Refer to NFPA-25 (2011 Edition), Section 13.4.3.2.2)

- Revise Fire Water System Program procedure(s) to remove, clean and inspect the strainers associated with electric tunnels and the containment purge exhaust system, primary auxiliary building exhaust system, and containment pressure relief filtration unit for damage and abnormal corrosion. (Refer to NFPA-25 (2011 Edition), Section 10.2.1.7.)

- Revise Fire Water System Program procedure(s) to perform an internal inspection every five years of the dry portion of the preaction system associated with the electric tunnels by removing a sprinkler toward the end of one branch line or using the inspector test valve for the purpose of inspecting for the presence of foreign organic and inorganic material. The procedure that governs inspection of the normally dry piping will include (1) guidance to perform an evaluation for MIC in the event tubercles or slime are identified, and (2) acceptance criteria that states “no abnormal debris” (i.e., no corrosion products that could impede flow or cause downstream components to become clogged). Corrective actions will specify that any signs of abnormal corrosion or blockage will be removed, the source and extent of condition determined and corrected, and entered into the corrective action program. (Refer to NFPA-25 (2011 Edition), Section 14.2.)

- Revise Fire Water System Program procedure(s) to perform an internal inspection every five years of the most remote dry piping downstream of the deluge valves in the deluge systems for the primary auxiliary building exhaust, containment purge, containment pressure relief, and foam systems by removing a sprinkler toward the end of one branch line for the purpose of inspecting for the presence of foreign organic and inorganic material. The procedure that governs inspection of the normally dry piping will include (1) guidance to perform an evaluation for MIC in the event tubercles or slime are identified, and (2) acceptance criteria that states “no abnormal debris” (i.e., no corrosion products that could impede flow or cause downstream components to become clogged). Corrective actions will specify that any signs of abnormal corrosion or blockage will be

removed, the source and extent of condition determined and corrected, and entered into the corrective action program. (Refer to NFPA-25 (2011 Edition), Section 14.2.)

- Revise IP3 Fire Water System Program procedures to ensure that the training and qualification of individuals involved in coating/lining inspections and evaluating degraded conditions for fire water storage tanks is conducted in accordance with an ASTM International standard endorsed in RG 1.54 including staff limitations associated with a particular standard.

- Revise IP3 Fire Water System Program procedures to incorporate the following guidance.

    - Acceptance criteria for inspections of coatings/linings in fire water storage tanks are as follows:

        a. Indications of peeling and delamination are not acceptable.

        b. Blisters are evaluated by a coatings 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 use of a particular standard.

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

- Revise IP3 Fire Water System Program procedures to incorporate the following guidance.

    - Coatings/linings for fire water storage tanks that do not meet acceptance criteria are repaired, replaced, or removed. Testing or examination is conducted to ensure that the extent of repaired or replaced coatings/linings encompasses sound coating/lining material.

    - As an alternative, coatings exhibiting indications of peeling and delamination may be returned to service if: (a) physical testing is conducted to ensure that the remaining coating is tightly bonded to the base metal; (b) the potential for further degradation of the coating is minimized, (i.e., any loose coating is removed, the edge of the remaining coating is feathered); (c) an evaluation is conducted of the potential impact on the system, including degraded performance of downstream components due to flow blockage and loss of material of the coated component; and (d) followup visual inspections of the degraded coating are conducted within

2 years from detection of the degraded condition, with a re-inspection within an additional 2 years, or until the degraded coating is repaired or replaced.

- If coatings/linings are credited for corrosion prevention (e.g., corrosion allowance in design calculations is zero, the "preventive actions" program element credited the coating/lining) and the base metal has been exposed or it is beneath a blister, the component's base material in the vicinity of the degraded coating/lining is examined to determine if the minimum wall thickness is met and will be met until the next inspection.

- If a blister is not repaired, physical testing is conducted to ensure that the blister is completely surrounded by sound coating/lining bonded to the surface, such as lightly tapping the coating/lining. Acceptance of a blister to remain in-service should be based both on the potential effects of flow blockage and degradation of the base material beneath the blister.

Enhancements will be implemented prior to December 31, 2019.

A.2.1.14 Flow-Accelerated Corrosion Program

The Flow-Accelerated Corrosion Program is an existing program that applies to safety-related and nonsafety-related carbon and low alloy steel components in systems containing high-energy fluids carrying two-phase or single-phase high-energy fluid more than two percent of plant operating time.

The program, based on EPRI guidelines in the Nuclear Safety Analysis Center (NSAC)-202L-R3 for an effective flow-accelerated corrosion program, predicts, detects, and monitors FAC in plant piping and other pressure retaining components. This program includes (a) an evaluation to determine critical locations, (b) initial operational inspections to determine the extent of thinning at these locations, and (c) follow-up inspections to confirm predictions. The program specifies repair or replacement of components as necessary. The aging effect of loss of material managed by the Flow Accelerated Corrosion Program is equivalent to the aging effect of wall thinning as defined in NUREG-1801 Volume 2 Table IX.E.

A.2.1.15 Flux Thimble Tube Inspection Program

The Flux Thimble Tube Inspection Program is an existing program that monitors for thinning of the flux thimble tube wall, which provides a path for the incore neutron flux monitoring system detectors and forms part of the RCS pressure boundary. Flux thimble tubes are subject to loss of material at certain locations in the reactor vessel where flow-induced fretting causes wear at discontinuities in the path from the reactor vessel instrument nozzle to the fuel assembly instrument guide tube. An NDE methodology, such as eddy current testing (ECT), is used to monitor for wear of the flux thimble tubes. This program implements the recommendations of NRC Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors".

The Flux Thimble Tube Inspection Program will be enhanced to include the following.

- Revise appropriate procedures to implement comparisons to wear rates identified in WCAP-12866. Include provisions to compare data to the previous performances and perform evaluations regarding change to test frequency and scope.

- Revise appropriate procedures to specify the acceptance criteria as outlined in WCAP-12866 or other plant-specific values based on evaluation of previous test results.

- Revise appropriate procedures to direct evaluation and performance of corrective actions based on tubes that exceed or are projected to exceed the acceptance criteria.

- Stipulate in procedures that flux thimble tubes that cannot be inspected over the tube length and can not be shown by analysis to be satisfactory for continued service, must be removed from service to ensure the integrity of the reactor coolant system pressure boundary.

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

A.2.1.16 Heat Exchanger Monitoring Program

The Heat Exchanger Monitoring Program is an existing plant-specific program that inspects heat exchangers for loss of material through visual or other non-destructive examination.

Heat exchanger tubes are inspected at frequencies based on plant-specific and application-specific knowledge, as well as past history, heat exchanger operating conditions, and heat exchanger availability. Inspection frequencies may be changed based on engineering evaluation of inspection results.

The Heat Exchanger Monitoring Program will be enhanced to include the following.

- Revise applicable procedures to include the following heat exchangers in the scope of the program.

  - safety injection pump lube oil heat exchangers
  - RHR heat exchangers
  - RHR pump seal coolers
  - non-regenerative heat exchangers
  - charging pump seal water heat exchangers
  - charging pump fluid drive coolers
  - charging pump crankcase oil coolers
  - spent fuel pit heat exchangers
  - secondary system steam generator sample coolers
  - waste gas compressor heat exchangers

- Revise appropriate procedures to perform visual inspection on heat exchangers where non-destructive examination, such as eddy current inspection, is not possible due to heat exchanger design limitations

- Revise appropriate procedures to include consideration of material-environment combination when determining sample population of heat exchangers.

- Revise appropriate procedures establishing the minimum tube wall thickness for the new heat exchangers identified in the scope of the program. Enhance appropriate procedures

establishing acceptance criteria for heat exchangers visually inspected to include no unacceptable signs of degradation.

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

A.2.1.17 Inservice Inspection – Inservice Inspection (ISI) Program

The ISI Program is an existing program based on ASME Section Xi Inspection Program B (Section XI, IWA-2432), which has ten-year inspection intervals. Every ten years the program is updated to the latest ASME Section XI code edition and addendum approved in 10 CFR 50.55a.

The program consists of periodic volumetric, surface, and visual examination of components and their supports for assessment of signs of degradation, flaw evaluation, and corrective actions.

On July 21, 2009, IP3 entered the fourth ISI interval. The ASME code edition and addenda used for the fourth interval is the 2001 Edition 2003 Addenda.

The current program ensures that the structural integrity of Class 1, 2, and 3 systems and associated supports is maintained at the level required by 10 CFR 50.55a.

A.2.1.18 Masonry Wall Program

The Masonry Wall Program is an existing program that manages aging effects so that the evaluation basis established for each masonry wall within the scope of license renewal remains valid through the period of extended operation.

The program includes visual inspection of all masonry walls identified as performing intended functions in accordance with 10 CFR 54.4. Included components are the 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 to include the following.

- Revise applicable procedures to specify that the IP1 intake structure is included in the program.

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

A.2.1.19 Metal-Enclosed Bus Inspection Program

The Metal-Enclosed Bus Inspection Program is an existing program that performs inspections on the following non-segregated phase bus.

- 6.9kV bus between station aux transformers and switchgear buses 1/2/3/4/5/6

- 6.9kV bus associated with the gas turbine substation

- 480V bus between emergency diesel generators and switchgear buses 2A/3A/5A/6A

Inspections of the metal enclosed bus (MEB) include the bus and bus connections, the bus enclosure assemblies, and the bus insulation and insulators. A sample of the accessible bolted connections will be inspected for loose connections. The bus enclosure assemblies will be inspected for loss of material and elastomer degradation. This program will be used instead of the Structures Monitoring Program for external surfaces of the bus enclosure assemblies. The internal portions of the MEB will be inspected for foreign debris, excessive dust buildup, and evidence of moisture intrusion. The bus insulation or insulators are inspected for degradation leading to reduced insulation resistance (IR). The bus insulation will be inspected for signs of embrittlement, cracking, melting, swelling, or discoloration, which may indicate overheating or aging degradation. The internal bus supports or insulators will be inspected for structural integrity and signs of cracks and corrosion. These inspections include visual inspections, as well as quantitative measurements, such as thermography or connection resistance measurements, as required.

The Metal-Enclosed Bus Inspection Program will be enhanced to include the following.

- Revise appropriate procedures to visually inspect the external surface of MEB enclosure assemblies for no unacceptable loss of material at least once every ten years. The first inspection will occur prior to the period of extended operation and the acceptance criterion will be no significant loss of material.

- Revise appropriate procedures to inspect bolted connections at least once every five years if only performed visually or at least once every ten years using quantitative measurements such as thermography or contact resistance measurements. The first inspection will occur prior to the period of extended operation.

- Revise acceptance criteria of appropriate procedures for MEB internal visual inspections that will include the absence of indications of dust accumulation on the bus bar, on the insulators, and in the duct, in addition to the absence of indications of moisture intrusion into the duct.

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

A.2.1.20 Nickel Alloy Inspection Program

The Nickel Alloy Inspection Program is an existing program that manages aging effects of Alloy 600 items and 82/182 welds in the reactor coolant system that are not addressed by the Reactor Vessel Head Penetration Inspection Program, Section A.2.1.30 or the Steam Generator Integrity Program, Section A.2.1.34. The aging effect requiring management for nickel alloys exposed to borated water at an elevated temperature is primary water stress corrosion cracking (PWSCC). The Nickel Alloy Inspection Program includes elements of the Inservice Inspection (ISI) Program, Section A.2.1.17, which specifies the nondestructive examination (NDE) techniques and acceptance criteria applied to evaluation of identified cracks, and the Boric Acid Corrosion Control Program, Section A.2.1.4. Also, the Water Chemistry Control - Primary and Secondary Program, Section A.2.1.40, maintains primary water in accordance with the Electric Power Research Institute (EPRI) guidelines to minimize the potential for crack initiation and growth.

The site commits to comply with future applicable NRC Orders. In addition, IPEC commits to implement applicable Bulletins and Generic Letters associated with nickel alloys and staff accepted industry guidelines associated with nickel alloys.

A.2.1.21 Non-EQ Bolted Cable Connections Program

The Non-EQ Bolted Cable Connections Program is a new program which monitors for loosening of bolted connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation. It provides for one-time inspections that will be completed on a sample of connections that will be completed prior to the period of extended operation. The following factors are considered for sampling: application (medium and low voltage, defined as < 35 kV), circuit loading (high loading), and location (high temperature, high humidity, vibration, etc.). The technical basis for the sample selections will be documented. If an unacceptable condition or situation is identified in the selected sample, the corrective action program will be used to evaluate additional requirements.

A.2.1.22 Non-EQ Inaccessible Medium-Voltage Cable Program

The Non-EQ Inaccessible Medium-Voltage Cable Program is a new program that entails periodic and event-driven inspections for water collection in cable manholes and periodic testing of cables. In scope medium-voltage cables (cables with operating voltage from 2kV to 35kV) and low-voltage power cables (400 V to 2 kV) exposed to significant moisture will be tested at least once every six years to provide an indication of the condition of the conductor insulation. Test frequencies are adjusted based on test results and operating experience.

The inspection frequency for water collection is established and performed based on plant specific operating experience with cable wetting or submergence in manholes (i.e., the inspection is performed periodically based on water accumulation over time and event driven occurrences, such as heavy rain or flooding).

The program includes periodic inspections for water accumulation in manholes at least once every year (annually). In addition to the periodic manhole inspections, mahole 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 Medium-Voltage Cable Program will be implemented prior to the period of extended operation. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.E3, Inaccessible Medium-Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements.

A.2.1.23 Non-EQ Instrumentation Circuits Test Review Program

The Non-EQ Instrumentation Circuits Test Review Program is a new program that 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 high range radiation monitors); 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 system (such as insulation resistance tests or time domain reflectometry) will occur at least every ten years, with the first test occurring before the period of extended operation. In accordance with the corrective action program, an engineering evaluation will be performed when test acceptance criteria are not met and corrective actions, including modified inspection frequency, will be implemented to ensure that the intended functions of the cables can be maintained consistent with the current licensing basis for the period of extended operation. This program will consider the technical information and guidance provided in NUREG/CR-5643, IEEE Std. P1205, SAND96-0344, and EPRI TR 109619.

The Non-EQ Instrumentation Circuits Test Review Program will be implemented prior to the period of extended operation. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.E2, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits.

A.2.1.24 Non-EQ Insulated Cables and Connections Program

The Non-EQ Insulated Cables and Connections Program is a new program that 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 significantly more severe than the specified service condition for the insulated cable or connection.

A representative sample of accessible insulated cables and connections within the scope of license renewal will be visually inspected for cable and connection jacket surface anomalies such as embrittlement, discoloration, cracking or surface contamination. The program sample consists of all accessible cables and connections in localized adverse environments.

The Non-EQ Insulated Cables and Connections Program will be implemented prior to the period of extended operation. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.E1, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.

A.2.1.25 Oil Analysis Program

The Oil Analysis Program is an existing program that maintains oil systems free of contaminants (primarily water and particulates) thereby preserving an environment that is not conducive to loss of material, cracking, or fouling. Activities include sampling and analysis of lubricating oil in accordance with industry standards such as ISO 4406, ASTM D445, ASTM D4951 and ASTM D96. Water, particle concentration and viscosity acceptance criteria are based on industry standards supplemented by manufacturer’s recommendations.

Oil analysis frequencies for IP3 equipment are based on Entergy templates with technical basis justifications. Procedure EN-DC-335, “PM Bases Template”, is based on EPRI PM bases

documents TR-106857 volumes 1 thru 39 and TR-103147. Each template contains sections describing failure location and cause, progression of degradation to failure, fault discovery and intervention, task content, and task objective. From information in these sections, frequencies are selected for the components managed by the Oil Analysis Program to mitigate failure.

The One-Time Inspection Program includes inspections planned to verify the effectiveness of the Oil Analysis Program.

The Oil Analysis Program will be enhanced to include the following.

- Revise appropriate procedures to sample and analyze generator seal oil and turbine hydraulic control oil (electrohydraulic fluid).

- Formalize preliminary oil screening for water and particulates and laboratory analyses including defined acceptance criteria for all components included in the scope of the program. The program will specify corrective actions in the event acceptance criteria are not met.

- Formalize trending of preliminary oil screening results as well as data provided from independent laboratories.

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

A.2.1.26 One-Time Inspection Program

The One-Time Inspection Program is a new program that includes measures to verify effectiveness of an aging management program (AMP) and confirm the absence of an aging effect. For structures and components that rely on an AMP, this program will verify effectiveness of the AMP by confirming that unacceptable degradation is not occurring and the intended function of a component will be maintained during the period of extended operation. One-time inspections may be needed to address concerns for potentially long incubation periods for certain aging effects on structures and components. There are cases where either (a) an aging effect is not expected to occur but there is insufficient data to completely rule it out, or (b) an aging effect is expected to progress very slowly. For these cases, there will be confirmation that either the aging effect is indeed not occurring, or the aging effect is occurring very slowly as not to affect the component or structure intended function. A one-time inspection of the subject component or structure is appropriate for this verification. The inspections will be nondestructive examinations (including visual, ultrasonic, and surface techniques).

The elements of the program include (a) determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience; (b) identification of the inspection locations in the system or component based on the aging effect; (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined; and (d) evaluation of the need for follow-up examinations to monitor the progression of any aging degradation.

A one-time inspection activity is used to verify the effectiveness of the water chemistry control programs by confirming that unacceptable cracking, loss of material, and fouling is not occurring

on components within systems covered by water chemistry control programs (Sections A.2.1.38, A.2.1.39, and A.2.1.40).

A one-time inspection activity is used to verify the effectiveness of the Oil Analysis Program by confirming that unacceptable cracking, loss of material and fouling are not occurring on components within systems covered by the Oil Analysis Program (Section A.2.1.25).

A one-time inspection activity is used to verify the effectiveness of the Diesel Fuel Monitoring Program by confirming that unacceptable loss of material and fouling is not occurring on components within systems covered by the Diesel Fuel Monitoring Program (Section A.2.1.8).

One-time inspection activities on the following confirm that loss of material is not occurring or is so insignificant that an aging management program is not warranted.

- internal surfaces of stainless steel drain piping, piping elements and components containing raw water (drain water)
- internal surfaces of stainless steel piping, piping elements and components in the station air containment penetration exposed to condensation
- internal surfaces of stainless steel EDG starting air tanks, piping, piping elements and components exposed to condensation
- internal surfaces of carbon steel and stainless steel tanks, piping, piping elements and components in the RCP oil collection system exposed to lube oil
- internal surfaces of auxiliary feedwater system stainless steel piping, piping elements and components exposed to treated water from the city water system
- internal surfaces of stainless steel piping, piping elements and components in the containment penetration for gas analyzers exposed to condensation
- internal surfaces of circulating water stainless steel and CASS piping, piping elements and components containing raw water
- internal surfaces of ammonia/morpholine addition system stainless steel piping, piping elements and components containing treated water
- internal surfaces of boron and layup chemical addition system stainless steel tanks, pump casings, piping, piping elements and components containing treated water
- internal surfaces of city water makeup system stainless steel and CASS piping, piping elements and components containing treated water (city water)
- internal surfaces of gaseous waste disposal system CASS piping, piping elements and components containing condensation
- internal surfaces of hydrazine addition system stainless steel tanks, pump casings, piping, piping elements and components containing treated water
- Internal surfaces of liquid waste disposal system stainless steel and CASS tanks, pump casings, piping, piping elements and components containing raw water or treated water (city water)
- internal surfaces of nuclear equipment drain system stainless steel tanks, piping, piping elements and components containing raw water
- Containment steel liner at the juncture with the concrete floor slab to assure liner degradation is not occurring

When evidence of an aging effect is revealed by a one-time inspection, routine evaluation of the inspection results will identify appropriate corrective actions.

The inspection will be performed prior to the period of extended operation. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M32, One-Time Inspection.

A.2.1.27 One-Time Inspection – Small Bore Piping Program

The One-Time Inspection - Small Bore Piping Program is a new program applicable to small bore ASME Code Class 1 piping less than 4 inches nominal pipe size (NPS 4), which includes pipe, fittings, and branch connections. The ASME Code does not require volumetric examination of Class 1 small bore piping. The One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program will manage cracking through the use of volumetric examinations.

The program will include a sample selected based on susceptibility, inspectability, dose considerations, operating experience, and limiting locations of the total population of ASME Code Class 1 small-bore piping locations.

When evidence of an aging effect is revealed by a one-time inspection, evaluation of the inspection results will identify appropriate corrective actions.

The inspection will be performed prior to the period of extended operation. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M35, One-Time Inspection of ASME Code Class I Small-Bore Piping.

A.2.1.28 Periodic Surveillance and Preventive Maintenance Program

The Periodic Surveillance and Preventive Maintenance Program is an existing program that includes periodic inspections and tests that manage aging effects not managed by other aging management programs. In addition to specific activities in the plant's preventive maintenance program and surveillance program, the Periodic Surveillance and Preventive Maintenance Program includes enhancements to add new activities. The preventive maintenance and surveillance testing activities are generally implemented through repetitive tasks or routine monitoring of plant operations.

Surveillance testing and periodic inspections using visual or other non-destructive examination techniques verify that the following components are capable of performing their intended function.

- reactor building cranes (polar and manipulator), crane rails, and girders, and refueling platform
- containment spray system sodium hydroxide tank
- recirculation pump motor cooling coils and housing
- city water system components
- charging pump casings
- plant drain components
- station air containment penetration piping
- HVAC duct flexible connections
- HVAC stored portable blowers and flexible trunks
- EDG exhaust components
- EDG duct flexible connections
- EDG air intake and aftercooler components

- EDG air start components
- EDG cooling water makeup supply valves
- security generator exhaust components
- security generator radiator tubes
- Appendix R diesel generator exhaust components
- Appendix R diesel generator radiator
- Appendix R diesel generator aftercooler
- Appendix R diesel generator starting air components
- Appendix R diesel generator crankcase exhaust components
- diesel fuel oil trailer transfer tank and associated valves
- auxiliary feedwater components
- containment cooling duct flexible connections
- containment cooling fan units internals
- control room HVAC condensers and evaporators
- control room HVAC ducts and drip pans
- control room HVAC duct flexible connections
- chlorination, circulating water, city water makeup, condensate pump suction, emergency diesel generator, floor drain, gaseous waste disposal, instrument air, liquid waste disposal, nuclear equipment drain, river water, station air piping, steam generator sampling, and secondary plant sampling piping components, and piping elements
- pressurizer relief tank
- main steam safety valve tailpipes
- atmospheric dump valve silencers
- auxiliary steam and condensate return system sight glass housings
- condensate transfer system sight glass housings
- heater drain/moisture separator drains/vents systems sight glass housings

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

- Program activity guidance documents will be developed or revised as necessary to assure that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

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

A.2.1.29 Reactor Head Closure Studs Program

The Reactor Head Closure Studs Program is an existing program that includes inservice inspection (ISI) in conformance with the requirements of the ASME Code, Section XI, Subsection IWB, and preventive measures (e.g. rust inhibitors, stable lubricants, appropriate materials) to mitigate cracking and loss of material of reactor head closure studs, nuts, washers, and bushings.

A.2.1.30 Reactor Vessel Head Penetration Inspection Program

The Reactor Vessel Head Penetration Inspection Program is an existing program that manages primary water stress corrosion cracking (PWSCC) of nickel-based alloy reactor vessel head penetrations exposed to borated water to ensure that the pressure boundary function is

maintained. This program was developed in response to NRC Order EA-03-009. The ASME Section XI, Subsection IWB Inservice Inspection and Water Chemistry Control Programs are used in conjunction with this program to manage cracking of the reactor vessel head penetrations. Detection of cracking is accomplished through implementation of a combination of bare metal visual examination (external surface of head) and non-visual examination (underside of head) techniques. Procedures are developed to perform reactor vessel head bare metal inspections and calculations of the susceptibility ranking of the plant.

The plant will continue to implement commitments associated with (1) NRC Orders, Bulletins and Generic Letters associated with nickel alloys and (2) staff-accepted industry guidelines.

A.2.1.31 Reactor Vessel Surveillance Program

The Reactor Vessel Surveillance Program is an existing program that manages reduction in fracture toughness of reactor vessel beltline materials to assure that the pressure boundary function of the reactor pressure vessel is maintained through the period of extended operation.

The Reactor Vessel Surveillance Program will be enhanced to include the following.

- The specimen capsule withdrawal schedules will be revised to draw and test a standby capsule to cover the peak reactor vessel fluence expected through the end of the period of extended operation.

- Appropriate procedures will be revised to require that tested and untested specimens from all capsules pulled from the reactor vessel are maintained in storage.

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

A.2.1.32 Selective Leaching Program

The Selective Leaching Program is a new program that ensures the integrity of components made of gray cast iron, bronze, brass, and other alloys exposed to raw water, treated water, or groundwater that may lead to selective leaching. The program includes a one-time visual inspection, hardness measurement (where feasible based on form and configuration), or other industry accepted mechanical inspection techniques of selected components that may be susceptible to selective leaching to determine whether loss of material due to selective leaching is occurring, and whether the process will affect the ability of the components to perform their intended function through the period of extended operation.

The Selective Leaching Program will be implemented prior to the period of extended operation. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M33 Selective Leaching of Materials.

A.2.1.33 Service Water Integrity Program

The Service Water Integrity Program is an existing program that relies on implementation of the recommendations of GL 89-13 to ensure that the effects of aging on the service water system are managed through the period of extended operation. The program includes component inspections for erosion, corrosion, and biofouling to verify the heat transfer capability of safety-related heat exchangers cooled by service water. Chemical treatment using biocides and

chlorine and periodic cleaning and flushing of infrequently used loops are methods used to control fouling within the heat exchangers and to manage loss of material in service water components. Scheduling of nonsafety-related piping examinations is determined by trending of examination results. Selection of large bore service water pipe points for volumetric inspection is based on piping configuration, results from previous inspections, consideration of follow-ups to previous repairs, and condition assessments when components are opened during preventive maintenance activities. Scope expansion for indications found by program inspections of nonsafety-related piping is based on engineering analysis, judgment and program experience. The factors that are considered include piping location, severity of use, piping materials, previous inspection results, and repair history.

The Service Water Integrity Program will be enhanced to include the following.

- Revise the appropriate procedures to incorporate actions to manage corrosion issues.
    - When through-wall leaks are detected, the leakage is evaluated under the corrective action program, which includes operability or functionality assessment of structural integrity and determination of appropriate corrective action.
    - Accessible portions of safety-related buried service water piping will be internally inspected by robotic crawler or manual crawl-through once during the first 10 years of the period of extended operation.

The enhancement will be implemented prior to December 31, 2019.

A.2.1.34 Steam Generator Integrity Program

The Steam Generator Integrity Program is an existing program that performs nondestructive examination (NDE) techniques to identify tubes that are defective and need to be removed from service or repaired in accordance with the guidelines of the plant technical specifications. The program also includes processes for monitoring and maintaining secondary side component integrity. The program defines when inspections and maintenance are performed, the scope of work, and the methods used.

The Steam Generator Integrity Program will be enhanced to include the following.

- Revise appropriate procedures to require that the results of the condition monitoring assessment are compared to the operational assessment performed for the prior operating cycle with differences evaluated.

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

A.2.1.35 Structures Monitoring Program

The Structures Monitoring Program is an existing program that performs inspections in accordance with 10 CFR 50.65 (Maintenance Rule) as addressed in Regulatory Guide 1.160 and NUMARC 93-01. Periodic inspections are used to monitor the condition of structures and structural commodities to ensure there is no loss of intended function.

The Structures Monitoring Program will be enhanced to include the following.

- Appropriate procedures will be revised to explicitly specify that the following structures are included in the program.

    - Appendix R diesel generator foundation
    - Appendix R diesel generator fuel oil tank vault
    - Appendix R diesel generator switchgear and enclosure
    - city water storage tanks foundation
    - condensate storage tank foundation
    - containment access facility and annex
    - discharge canal
    - emergency lighting poles and foundations
    - fire protection pumphouse
    - fire water storage tanks foundations
    - gas turbine 2/3 fuel storage tank foundation
    - primary water storage tank foundation
    - refueling water storage tank foundation
    - security access and office building
    - service water pipe chase
    - service water valve pit
    - waste holdup tank pit

- Appropriate procedures will be revised to clarify that in addition to structural steel and concrete, the following commodities (including their anchorages) are inspected for each structure as applicable.

    - cable trays and supports
    - concrete portion of reactor vessel supports
    - conduits and supports
    - cranes, rails, and girders
    - equipment pads and foundations
    - structural steel fireproofing
    - HVAC duct supports
    - jib cranes
    - manholes and duct banks
    - manways, hatches, and hatch covers
    - monorails
    - new fuel storage racks
    - sumps

- Guidance will be added to the Structures Monitoring Program to inspect inaccessible concrete areas that are exposed by excavation for any reason. The site will also inspect inaccessible concrete areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant concrete degradation is occurring.

- Revise applicable structures monitoring procedures for inspection of elastomers (seals, gaskets, seismic joint filler, and roof elastomers) to identify cracking and change in

material properties and for inspection of aluminum vents and louvers to identify loss of material.

- Guidance to perform evaluation of groundwater samples will be added to the Structures Monitoring Program. To assess the aggressiveness of groundwater to concrete, IPEC will obtain samples from at least five wells that are representative of the ground water surrounding below-grade site structures at least once every five years and perform an engineering evaluation of the results from those samples for sulfates, pH and chlorides.

- Revise applicable structures monitoring procedures to inspect normally submerged concrete portions of the intake structures at least once every 5 years. Also, inspect the baffling/grating partition and support platform of the intake structure at least once every 5 years.

- Enhance the Structures Monitoring Program to perform inspection of the degraded areas of the water control structure once every three years rather than the normal frequency of once every five years during the period of extended operation.

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

A.2.1.36 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program

The Thermal Aging Embrittlement of CASS Program is a new program that augments the inspection of the reactor coolant system components in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI. The inspection detects the effects of loss of fracture toughness due to thermal aging embrittlement of cast austenitic stainless steel (CASS) components. This aging management program determines the susceptibility of CASS components to thermal aging embrittlement based on casting method, molybdenum content, and percent ferrite. The program provides aging management through either enhanced volumetric examination or flaw tolerance evaluation. Additional inspection or evaluations to demonstrate that the material has adequate fracture toughness are not required for components that are not susceptible to thermal aging embrittlement.

The Thermal Aging Embrittlement of CASS Program will be implemented prior to the period of extended operation. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M12, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program.

A.2.1.37 Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program

The Thermal Aging and Neutron Irradiation Embrittlement of CASS Program is a new program that augments the reactor vessel internals visual inspection in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI, Subsection IWB. This inspection manages the effects of loss of fracture toughness due to thermal aging and neutron embrittlement of cast austenitic stainless steel (CASS) components. This aging management program determines the susceptibility of CASS components to thermal aging or neutron irradiation (neutron fluence) embrittlement based on casting method,

molybdenum content, operating temperature and percent ferrite. For each "potentially susceptible" component, aging management is accomplished through either a component-specific evaluation or a supplemental examination of the affected component as part of the inservice inspection (ISI) program during the license renewal term.

The Thermal Aging and Neutron Irradiation Embrittlement of CASS Program will be implemented prior to the period of extended operation. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M13, Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program.

A.2.1.38 Water Chemistry Control – Auxiliary Systems Program

The Water Chemistry Control – Auxiliary Systems Program is an existing program that manages loss of material and cracking for components exposed to treated water.

Program activities include sampling and analysis to minimize component exposure to aggressive environments for stator cooling water systems.

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

A.2.1.39 Water Chemistry Control – Closed Cooling Water Program

The Water Chemistry Control – Closed Cooling Water Program is an existing program that includes preventive measures that manage loss of material, cracking, and fouling for components in closed cooling water systems (component cooling water (CCW), instrument air closed cooling (IACC), emergency diesel generator cooling, security generator cooling, Appendix R diesel generator cooling, and turbine hall closed cooling (THCC)). These chemistry activities provide for monitoring and controlling closed cooling water chemistry using procedures and processes based on EPRI guidance for closed cooling water chemistry.

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

The Water Chemistry Control – Closed Cooling Water Program will be enhanced to include the following.

- Revise appropriate procedures to maintain security generator and fire protection diesel cooling water pH and glycol within limits specified by EPRI guidelines.

Enhancements will be implemented prior to the period of extended operation

A.2.1.40 Water Chemistry Control – Primary and Secondary

The Water Chemistry Control – Primary and Secondary Program is an existing program that manages aging effects caused by corrosion and cracking mechanisms. The program relies on monitoring and control of reactor water chemistry based on the EPRI guidelines in TR-105714 for primary water chemistry and TR-102134 for secondary water chemistry.

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

A.2.1.41 Reactor Vessel Internals Aging Management Activities

The Reactor Vessel Internals (RVI) Program is a new plant specific program to manage aging effects of reactor vessel internals using the guidance from the Electric Power Research Institute (EPRI) Materials Reliability Program (MRP). The MRP inspection and evaluation (I&E) guidelines for managing the effects of aging on pressurized water reactor vessel internals are presented in MRP-227-A, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines." The MRP also developed inspection requirements specific to the inspection methods delineated in MRP-227-A, as well as requirements for qualification of the nondestructive examination (NDE) systems used to perform those inspections. These inspection requirements are presented in MRP-228, "Materials Reliability Program: Inspection Standard for PWR Internals."

MRP-227-A and MRP-228 provide the basis of the IPEC Reactor Vessel Internals (RVI) Program. The RVI Program will monitor the effects of aging degradation mechanisms on the intended function of the internals through periodic and conditional examinations. The RVI Program will detect and evaluate cracking, loss of material, reduction of fracture toughness, loss of preload and dimensional changes of vessel internals components in accordance with MRP-227-A inspection requirements and evaluation acceptance criteria.

The IPEC RVI Program will be implemented and maintained in accordance with the guidance in NEI 03-08 [Addenda], Addendum A, “RCS Materials Degradation Management Program Guidelines.” Any deviations from mandatory, needed, or good practice implementation requirements established in MRP-227-A or MRP-228, will be resolved in accordance with the NEI 03-08 implementation protocol. The RVI Program will be implemented prior to the period of extended operation.

A.2.1.42 Coating Integrity

The Coating Integrity Program is a new program that will include periodic visual inspections of coatings/linings applied to the internal surfaces of in-scope components where loss of coating or lining integrity could impact the component’s and downstream component’s current licensing basis intended function(s). For coated/lined surfaces determined to not meet the acceptance criteria, physical testing is performed where physically possible in conjunction with the visual inspection. The training and qualification of individuals involved in coating/lining inspections of noncementitious coatings/linings are conducted in accordance with ASTM standards endorsed in RG 1.54 including guidance from the staff associated with a particular standard. For cementitious coatings, training and qualifications are based on an appropriate combination of education and experience related to inspecting concrete surfaces.

This program will be implemented prior to December 31, 2024.

A.2.2 Evaluation of Time-Limited Aging Analyses – Unit 3

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

A.2.2.1 Reactor Vessel Neutron Embrittlement

The current licensing basis analyses evaluating reduction of fracture toughness of the reactor vessel for 40 years are TLAA. The reactor vessel neutron embrittlement TLAA is summarized below. Forty-eight effective full-power years (EFPY) are conservatively projected for the end of the period of extended operation (60 years) based on actual capacity factors from the start of commercial operation until 2005 and an average capacity factor of 99% from 2005 to the end of the period of extended operation.

A.2.2.1.1 Reactor Vessel Fluence

As part of the stretch power uprate analysis, the neutron exposure levels for the reactor pressure vessel were projected for an operating period extending to 48 EFPY. These fluence values included peak vessel ID fluences. The 1/4 T fluence was derived using RG 1.99 formula and conservative wall thicknesses.

A.2.2.1.2 Pressure-Temperature Limits

Appendix G of 10 CFR 50 requires operation of the reactor pressure vessel be accomplished within established pressure-temperature (P-T) limits. These limits are established by calculations that utilize the materials and fluence data obtained through the unit specific reactor surveillance capsule program.

Technical Specifications contain pressure/temperature limits valid through 34 EFPY including the effects of power uprate.

IP3 will submit additional P-T curves as 10 CFR 50, Appendix G requires prior to the period of extended operation as part of the Reactor Vessel Surveillance Program. LTOP (PORV) setpoints will be re-evaluated when pressure/temperature curves are submitted.

A.2.2.1.3 Charpy Upper-Shelf Energy

The predictions for percent drop in C_VUSE at 48 EFPY are based on chemistry data, unirradiated C_VUSE data, and 1/4 T fluence values. The projected 48 EFPY peak beltline fluence level was conservatively applied to all beltline materials.

One lower shell plate (B2803-3) has a projected upper shelf energy level below 50 ft-lb during the period of extended operation. All remaining plate and weld beltline materials meet the requirement of exceed 50 ft-lb at 48 EFPY.

An equivalent margins analysis performed in WCAP-13587, Rev. 1, demonstrated that the minimum acceptable USE for reactor vessel plate material in four-loop plants is 43 ftlbs. In the safety assessment of WCAP-13587, the NRC concluded the report demonstrated margins of safety equivalent to those of the ASME code for beltline plate and forging materials. The USE value is therefore acceptable since the projected USE level through the period of extended

operation of 49.8 ft-lb for lower shell plate B2003-3 is above the 43 ft-lbs minimum acceptable USE for four-loop plants determined in WCAP-13587 Rev. 1.

A.2.2.1.4 Pressurized Thermal Shock

10 CFR 50.61(b)(1) provides rules for protection against pressurized thermal shock events for pressurized water reactors. Licensees are required to perform an assessment of the projected values of reference temperature whenever a significant change occurs in projected values of the adjusted reference temperature for pressurized thermal shock (RT_{PTS}). The screening criteria for RT_{PTS} is 270°F for plates, forgings, and axial welds and 300°F for circumferential welds.

Adjusted reference temperatures are calculated for both Positions 1 and 2 by following the guidance in Regulatory Guide 1.99, Sections 1.1 and 2.1, respectively, using copper and nickel content of beltline materials and end-of-life (EOL) best estimate fluence projections.

All projected RT_{PTS} values are within the established screening criteria for 48 EFPY with the exception of plate B2803-3, which exceeds the screening criterion by 9.9°F.

As required by 10 CFR 50.61(b)(4), a plant-specific safety analysis for plate B2803-3 will be submitted to the NRC three years prior to reaching the RT_{PTS} screening criterion. Alternatively, the site may choose to implement the revised PTS rule when approved.

A.2.2.2 Metal Fatigue

A.2.2.2.1 Class 1 Metal Fatigue

Class 1 components evaluated for fatigue and flaw growth include the reactor pressure vessel (RPV), pressurizer, steam generators, reactor coolant pumps, control rod drive mechanisms, regenerative letdown heat exchanger, and Class 1 piping and in-line components.

The Fatigue Monitoring Program will assure that the analyzed number of transient cycles is not exceeded. The program requires corrective action if the analyzed number of transient cycles is approached. Consequently, the effects of aging related to these TLAA (fatigue analyses) based on those transients will be managed by the Fatigue Monitoring Program in accordance with 10 CFR 54.21(c)(1)(iii).

A.2.2.2.2 Non-Class 1 Metal Fatigue

For non-Class 1 piping and in-line components identified as subject to cracking due to fatigue, a review of system operating characteristics was conducted to determine the approximate frequency of any significant thermal cycling. If the number of equivalent full temperature cycles is below the limit used for the original design (usually 7000 cycles), the component is suitable for extended operation. If the number of equivalent full temperature cycles exceeds the limit, the individual stress calculations require evaluation. No systems were identified with projected cycles exceeding 7000. Therefore, the TLAA for non-Class 1 piping and in-line components remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(i).

A.2.2.2.3 Subsection NG Fatigue Analysis of Reactor Pressure Vessel Internals

The reactor vessel internals were designed to meet the intent of Subsection NG of the ASME Boiler and Pressure Vessel Code, Section III. Subsequent plant uprate evaluations determined CUFs for some reactor vessel internals components. These evaluations were performed to the intent of Subsection NG. The Fatigue Monitoring Program manages the effects of aging related to these TLAAs (fatigue analyses) in accordance with 10 CFR54.21(c)(1)(iii).

Each of the limiting CUFs for the reactor vessel internals will be recalculated prior to December 12, 2015, to include the reactor coolant environment effects (F_{en}) as provided in the Fatigue Monitoring Program using NUREG/CR-5704 or NUREG/CR-6909. Corrective actions specified in the Fatigue Monitoring Program include further CUF reanalysis and/or repair or replacement of the affected components prior to the CUF_{en} reaching 1.0.

A.2.2.2.4 Environmental Effects on Fatigue

The effects of reactor water environment on fatigue were evaluated for license renewal. Projected cumulative usage factors (CUFs) were calculated for the limiting locations based on NUREG/CR-6260. The identified IP3 locations are those listed in the license renewal application, Table 4.3-14. Several locations may exceed a CUF of 1.0 with consideration of environmental effects during the period of extended operation. The Fatigue Monitoring Program requires that at least two years prior to entering the period of extended operation the site will implement one or more of the following:

(1) Consistent with the Fatigue Monitoring Program, Detection of Aging Effects, update the fatigue usage calculation 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 in accordance with one of the following.

For locations with existing fatigue analysis valid for the period of extended operation, use the existing CUF.

Additional plant-specific locations with a valid CUF may evaluated. In particular, the pressurizer lower shell will be reviewed to ensure the surge nozzle remains the limiting component.

Representative CUF values from other plants, adjusted to or enveloping the plant-specific external loads may be used if demonstrated applicable.

An analysis using an NRC-approved version of the ASME code or NRC-approved alternative (e.g., NRC-approved code case) may be performed to determine a valid CUF.

(2) Consistent with the Fatigue Monitoring Program, Corrective Actions, repair or replace the affected locations before exceeding a CUF of 1.0.

A.2.2.3 Environmental Qualification of Electrical Components

The EQ 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 TLAAs will be adequately managed such that the intended functions can be maintained for the period of extended operation.

A.2.2.4 Containment Liner Plate and Penetrations Fatigue Analyses

There are no TLAA associated with the containment liner plate or the containment penetrations.

A.2.2.5 Leak before Break

Leak before break (LBB) analyses evaluate postulated flaw growth in piping to justify changes to the structural design basis involving protection against the effect of postulated reactor coolant loop pipe ruptures. The LBB evaluations use saturated (fully aged) fracture toughness properties, these analyses do not have a material property time-limited assumption. The fatigue crack growth for 40 years was calculated using the design transients for the reactor vessel. As these transients will not be exceeded in 60 years, these analyses will remain valid during the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.2.2.6 Steam Generator Flow-Induced Vibration and Tube Wear

The steam generators were evaluated with respect to flow-induced vibration. The projected tube wear is 2.8 mils (~5.7% through-wall wear) by the end of the period of extended operation. Therefore, the TLAA associated with tube wear has been projected to the end of the period of extended operation in accordance with 10 CFR 54(21)(c)(1)(ii).

A.2.3 References

A.2-1 Letter from F. Dacimo, Indian Point Energy Center, to Document Control Desk, NRC, *License Renewal Application,* dated April 23, 2007

A.2-2 NRC Safety Evaluation Report (SER), *Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3*, dated October 2009, Supplement 1, dated August 2011, and Supplement 2, dated November 2014