Entergy

Entergy Operations, Inc.
17265 River Road
Killona, LA 70057-3093
Tel 504-739-6660
Fax 504-739-6698
mchisum@entergy.com

Michael R. Chisum
Site Vice President
Waterford 3

W3F1-2017-0015

March 16, 2017

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555-0001

SUBJECT: Responses to Request for Additional Information Set 13 Regarding the License Renewal Application for Waterford Steam Electric Station, Unit 3 (Waterford 3)
Docket No. 50-382
License No. NPF-38

REFERENCES:

1. Entergy letter W3F1-2016-0012 "License Renewal Application, Waterford Steam Electric Station, Unit 3" dated March 23, 2016.
2. NRC letter to Entergy "Requests for Additional Information for the Review of the Waterford Steam Electric Station, Unit 3, License Renewal Application – Set 13" dated February 14, 2017.
3. Entergy letter W3F1-2016-0071 "Responses to Request for Additional Information Set 4 Regarding the License Renewal Application for Waterford Steam Electric Station, Unit 3" dated January 9, 2017.
4. Entergy letter W3F1-2016-0075 "Responses to Request for Additional Information Set 6 Regarding the License Renewal Application for Waterford Steam Electric Station, Unit 3" dated December 7, 2016.

Dear Sir or Madam:

By letter dated March 23, 2016, Entergy Operations, Inc. (Entergy) submitted a license renewal application (Reference 1).

In letter dated February 14, 2017 (Reference 2), the NRC staff made a Request for Additional Information (RAI) Set 13, needed to complete its review. Enclosure 1 provides the responses to the Set 13 RAIs. Enclosure 2 contains revised responses to RAI B.1.28-2 and RAI 3.5.1.79-1 which supersedes the response originally provided in References 3 and 4, respectively. Lastly, Enclosure 3 contains a correction to LRA Table 3.3.2-15-17 that was provided in Reference 1.

There are no new regulatory commitments contained in this submittal. If you require additional information, please contact the Regulatory Assurance Manager, John Jarrell, at 504-739-6685.

I declare under penalty of perjury that the foregoing is true and correct. Executed on March 16, 2017.

Sincerely,

MRC/AJH

Enclosures:
1. Set 13 RAI Responses – Waterford 3 License Renewal Application
2. RAI B.1.28-2 and RAI 3.5.1.79-1 Revised Responses
3. LRA Table 3.3.2-15-17 Correction

cc:

Kriss Kennedy
Regional Administrator
U. S. Nuclear Regulatory Commission
Region IV
1600 E. Lamar Blvd.
Arlington, TX 76011-4511
RidsRgn4MailCenter@nrc.gov

NRC Senior Resident Inspector
Waterford Steam Electric Station Unit 3
P.O. Box 822
Killona, LA 70066-0751
Frances.Ramirez@nrc.gov
Chris.Speer@nrc.gov

U. S. Nuclear Regulatory Commission
Attn: Phyllis Clark
Division of License Renewal
Washington, DC 20555-0001
Phyllis.Clark@nrc.gov

U. S. Nuclear Regulatory Commission
Attn: Dr. April Pulvirenti
Washington, DC 20555-0001
April.Pulvirenti@nrc.gov

Louisiana Department of Environmental Quality
Office of Environmental Compliance
Surveillance Division
P.O. Box 4312
Baton Rouge, LA 70821-4312
Ji.Wiley@LA.gov

Enclosure 1 to

W3F1-2017-0015

Set 13 RAI Responses
Waterford 3 License Renewal Application

RAI 4.3.2-2

Background:

LRA Section 4.3.2.1 discusses the TLAA for non-Class 1 piping and in-line components. The LRA states that for the applicable systems, the projected 60-year thermal cycle counts for these piping and in-line components indicate that 7000 thermal cycles will not be exceeded, and therefore, the non-Class 1 pipe stress calculations are valid for the period of extended operation. The applicant dispositioned this TLAA in accordance with 10 CFR 54.21(c)(1)(i).

Issue:
The LRA did not clarify which thermal transients were used in the fatigue analyses of non-Class 1 piping and in-line components. The staff does not have sufficient information on the thermal transients and their projected cycle counts to confirm that 7000 thermal cycles will not be exceeded and to determine the validity of the applicant's disposition of the TLAA.

Request:
Justify that the 7000 thermal cycle limit will not be exceeded during the period of extended operation such that the stress calculations will remain valid for these non-Class 1 piping and in-line components

Waterford 3 Response

As identified in LRA Section 4.3.2, for non-Class 1 systems a stress range reduction factor of 1.0 in the stress analyses applies for up to 7000 thermal cycles. The allowable stress range is reduced by the stress range reduction factor if the number of thermal cycles exceeds 7000. Thermal cycles have been projected for 60 years of plant operation. These projections, described below, indicate that 7000 thermal cycles will not be exceeded for 60 years of operation. Therefore, the piping and in-line component calculations are valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

Containment Spray (LRA Section 3.2.2.1.1)

Portions of the containment spray system are in-line with the shutdown cooling heat exchanger and exposed to temperatures above the fatigue threshold when the shutdown cooling heat exchangers are in service as part of the normal reactor coolant system cooldown. Reactor coolant system cooldowns are tracked per LRA Table 4.3-1 with an allowable value of 300 cycles. Therefore, the number of cycles will not exceed 7000 cycles on the portions of the system used as part of shutdown cooling.

Safety Injection (LRA Section 3.2.2.1.2)

Portions of the safety injection system are exposed to temperatures above the fatigue threshold when the shutdown cooling heat exchangers are in service as part of the normal reactor coolant system cooldown. Reactor coolant system cooldowns are tracked per LRA Table 4.3-1 with an allowable value of 300 cycles. Therefore, the number of cycles will not exceed 7000 cycles on the portions of the system used as part of shutdown cooling.

Containment Penetrations (LRA Section 3.2.2.1.3)

This LRA section includes containment penetrations not covered in other AMRRs. The penetrations associated with sampling have piping and valves exposed to elevated temperatures during sampling. The sampling system evaluation is provided in the nonsafety-related affecting safety-related discussion below.

Chemical and Volume Control System (LRA Section 3.3.2.1.1)

The chemical and volume control system piping exposed to temperatures above the fatigue threshold is connected to the RCS. This piping is heated up as part of the plant heat-up and can experience temperature transients during the loss of charging and letdown transients. The chemical and volume control system will not exceed 7,000 cycles during the period of extended operation because the allowable numbers of heatups and cooldowns plus loss of charging and letdown transients is less than 7000. LRA Table 4.3-1 shows the allowable numbers of these transients.

Emergency Generator System (LRA Section 3.3.2.1.7)

The emergency diesel generators are tested monthly (~720 cycles in 60 years) and every 18 months (~40 cycles in 60 years). Emergency diesel generator actuations occur less frequently than the testing. Thus, the total number of cycles in 60 years will not exceed 7000.

Fire Protection: Water System (LRA Section 3.3.2.1.8)

The fire protection: water system includes two diesel-driven fire pumps. The diesel engine exhaust piping is exposed to elevated temperatures when the diesels are operated. The diesel-driven fire pumps are tested monthly (12x60 = 720 cycles). Actuations outside of testing occur less frequently than testing. Therefore, pump operation will not result in exceeding 7000 cycles in the PEO.

Auxiliary Diesel Generator (LRA Section 3.3.2.1.13)

The auxiliary diesel generator diesel engine exhaust piping is exposed to elevated temperatures when the diesel is operated. The auxiliary diesel generator diesel engine is tested monthly. Operation outside of testing occurs less frequently than testing. Therefore, engine operation will not result in exceeding 7000 cycles in the PEO.

Main Feedwater System (LRA Section 3.4.2.1.3)

The main feedwater system is heated up as part of the plant heat-up and power escalation. The main feedwater system will not exceed 7,000 temperature cycles during the period of extended operation because the allowable number of heatups and cooldowns per LRA Table 4.3-1 is less than 7000.

Main Steam System (LRA Section 3.4.2.1.4)

The main steam system is heated up as part of the plant heat-up. The main steam system will not exceed 7,000 cycles during the period of extended operation because the allowable number of heatups and cooldowns per LRA Table 4.3-1 is less than 7000.

Nonsafety-related Affecting Safety-related (LRA Sections 3.3.2.1.15 and 3.4.2.1.5)

The main steam and blowdown systems are heated up and cooled down with the reactor coolant system heatups and cooldowns. As such, these systems will not exceed 7,000 cycles during the period of extended operation because the allowable number of heatups and cooldowns per LRA Table 4.3-1 is less than 7000.

The auxiliary steam system provides heating steam and typically cycles several times per year as environmental conditions change. Cycling 100 times per year will result in only 6000 cycles in 60 years, so the number of cycles for these systems will remain below 7000.

Sample lines for each system were reviewed. Sample point P-1 (RCS hot leg) piping is thermally cycled once per month and during quarterly testing. The sample point P-2 (pressurizer surge line) piping is thermally cycled once per week and during quarterly testing. The sample point P-3 (pressurizer steam space) piping is cycled infrequently to degas the RCS and during quarterly testing. The sample points P-4A(B) (shutdown cooling suction lines) are not normal sample paths. The sample points P-5A(B) (high pressure safety injection pump discharge) are not normal sample paths. Sample points P-6, 7, 8, and 9 (purification filter, ion exchanger, and VCT) normally run less than 140°F. Sample points S-1 and S-2 (main steam line) are continuous samples and are isolated once per cycle and during quarterly testing. Sample point S-7 (combined heater drain pump discharge) is a continuous sample and isolated once per cycle. Sample point S-8 (combined header outlet) is a continuous sample and is isolated once per cycle. Sample points S-8A-D (MSR drain tanks) are continuous samples and are isolated once per cycle. Sample point S-8E (feedwater pump suction) is not normally used. Sample points S-21B and S-22B (steam generator blowdown) are continuous samples and isolated once per cycle and during quarterly testing. Therefore, the WF3 sample lines will not exceed 7000 cycles through the period of extended operation.

RAI B.1.36-4a

Background:

The RAI response dated December 12, 2016, states that erosion is addressed through preventive maintenance activities on valves ACC-126A and ACC-126B by removing the valves and visually inspecting the valves and piping in accordance with EN-DC-184, Attachment 9.2.[3][4]. The response notes that routine NDE inspections addressed in EN-DC-184, Attachment 9.3 are not needed because the visual inspections of areas with known susceptibility to erosion are implemented through the routine inspections of the valves and piping. To clarify this information, the response modified LRA Sections A.1.36 and B.1.36 to state that the Service Water Integrity program manages loss of material due to cavitation erosion by periodic visual inspections of susceptible locations.

Issue:

LRA Table 3.3.2-3 includes an aging management review item for carbon steel valve bodies exposed to raw water that are being managed for loss of material due to erosion by the Flow-Accelerated Corrosion program. The discussion in WF3-ME-14-00009, Section 3.1.1 notes that the erosion aging mechanism only applies to select carbon steel valves in the ACC system, and Section 4.4 notes that the Flow-Accelerated Corrosion program monitors locations for wall thickness changes. Since the response clarified that the valves in the ACC system are being managed for erosion by the SWI program, it is unclear to the staff what components in the ACC system are being managed for erosion by the Flow-Accelerated Corrosion program.

.

Request:

Clarify which specific components in the ACC system are within the scope of the Flow-Accelerated Corrosion program as shown in LRA Table 3.3.2-3 and WF3-ME-14-00009. If the only components are valves ACC-126A and ACC-126B, explain why the current aging management activities described in the initial response need to be augmented by the Flow-Accelerated Corrosion program. In addition, explain why EN-DC-184 Attachment 9.1 does not show any procedural relation with EN-DC-315, Flow-Accelerated Corrosion program similar to the interrelationships shown for procedures EN-DC-316, EN-DC-340, and EN-DC-343.

Waterford 3 Response

There are no components in the ACC system subject to aging management review for which the Flow-Accelerated Corrosion Program manages the effects of aging. Therefore, there is no procedural relationship between EN-DC-184 and EN-DC-315 for WF3. EN-DC-315 does not supplement EN-DC-184 in implementing the SWI Program. LRA Section 3.3.2.1.3, Item 3.3.1-126 in Table 3.3.1, and Table 3.3.2-3 are revised to indicate the Service Water Integrity Program manages loss of material due to erosion for the carbon steel valves exposed to raw water. This is consistent with NRC Generic Letter (GL) 89-13, Action III.

Additions are underlined and deletions marked through.

LRA Section 3.3.2.1.3

Aging Management Programs

The following aging management programs manage the aging effects for the component cooling and auxiliary component cooling water system components.

• Bolting Integrity
• Buried and Underground Piping and Tanks Inspection
• Coating Integrity
• External Surfaces Monitoring
• ~~Flow-Accelerated Corrosion~~
• Oil Analysis
• One-Time Inspection
• Periodic Surveillance and Preventive Maintenance
• Selective Leaching
• Service Water Integrity
• Water Chemistry Control – Closed Treated Water Systems

LRA Table 3.3.1

	Any material, piping, piping components, and piping elements exposed to treated water, treated water (borated), raw water	Wall thinning due to erosion	Chapter XI.M17, "Flow-Accelerated Corrosion"	No	~~Consistent with NUREG-1801.~~ Loss of material due to erosion for steel components exposed to raw water is managed by the ~~Flow-Accelerated Corrosion~~ Service Water Integrity Program using periodic visual inspections.

LRA Table 3.3.2-3

Valve body	Pressure boundary	Carbon steel	Raw water (int)	Loss of material – erosion	~~Flow-Accelerated Corrosion~~ Service Water Integrity	VII.C1.A-409	3.3.1-126	~~A~~E

RAI B.1.36-5a

Background:

The RAI response dated December 12, 2016, states that based on the response to GL 89-13, the provisions of EN-DC-184 step 5.0[6](a)(2) regarding flushing of infrequently used systems did not apply to the ACCW system. However, it also states that the piping from the ACCW system to the emergency feedwater system was identified as needing flushing in accordance with the same step in EN-DC-184 and states that "the enhancement to the SWI program makes these activities part of the program."

Issue:

It is unclear to the staff why Waterford's response to GL 89-13 Action 1 did not include the periodic flushing and flow testing for infrequently used cooling loops as discussed in the generic letter. Although bulk chemistry of the ACCW basins may have been maintained through weekly operation for chemistry testing, it is not clear that this would apply to the portion of the ACCW system piping that supplies cooling water to the emergency feedwater system. In addition, LER 382/1994-004 indicates that controls of the ACCW basin water chemistry were not adequate at some point. Furthermore, although Waterford's current program, EN-DC-184, includes a flushing requirement in step 5.0[6](a)(2), the need for the enhancement *("Revise Service Water Integrity Program procedures to (1) flush redundant, infrequently flowed sections, and stagnant lines…")* indicates that the current implementing procedures do not meet the current program. This is reiterated through the statement in the RAI response that the enhancement "makes these [flushing] activities part of the program."

Request:

Provide additional bases to show that the current SWI program does not need to include periodic flushing of the of the ACC system piping that supplies cooling water to the emergency feedwater system, such that an enhancement to the SWI program is warranted. If other information is available, discuss additional bases for not including a commitment related to this in Waterford's response to GL 89-13.

Waterford 3 Response

During preparation of the Waterford 3 license renewal application, Entergy identified a need to flush infrequently used flow paths. These flow paths include the flow path from the ACCW system to the EFW system. While quarterly flushing of the flow path from ACCW to EFW had been in place since 1997, requirements for periodic flushing of the CW to ACCW basin makeup flow path were not identified. The enhancement in the license renewal application to flush infrequently used flow paths was written in a general sense to include all necessary flow paths as identified in the Entergy fleet procedure for Generic Letter 89-13 Service Water programs.

A Condition Report has been entered into the site's corrective action program to identify flushing requirements for infrequently used loops that should be included in the Service Water Program.

RAI 3.3.2.7-2

Background:

Section 54.21(a)(3) of 10 CFR requires the applicant to demonstrate that the effects of aging for structures and components will be adequately managed so that the intended function will be maintained consistent with the current licensing basis for the period of extended operation.

LRA Table 3.3.2-7, "Emergency Diesel Generator System," states that the carbon steel tanks exposed to concrete are not susceptible to an aging effect requiring management. This item cites generic note G and plant-specific note 304. Plant-specific note 304 states that "this tank is located indoors and is seated on (not embedded in) concrete."

LR-ISG-2012, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation," states that "although the likelihood of moisture penetrating the interface between these indoor tanks and the concrete surface on which they sit is low, corrosion can occur." Additionally, LR-ISG-2012-02 includes aging management review item 3.3.1-129 for the Aboveground Metallic Tanks AMP which states that steel tanks exposed to various environments, including concrete, may be susceptible to loss of material due to general, pitting, and crevice corrosion.

Issue:

If moisture is allowed to enter the interface between the tank and concrete, the tank bottom may be susceptible to loss of material. Since LRA Table 3.0-1 defines "air-indoor" as air with steam or water leakage, it is unclear to the staff that the tank's bottom surface is not susceptible to general, pitting, or crevice corrosion if there are sources of water near the tank.

Request:

1. If the portion of the tank exposed to concrete is not susceptible to an aging effect requiring management, provide information that:
   a. describes the configuration of the interface between the tank bottom and concrete floor to show that moisture is not likely to enter and cause corrosion, or
   b. confirms that there are no water sources near the tank (e.g., groundwater inleakage, leaking pipes, and components operating at temperatures below the dew point) and that there are no past occurrences where water entered the tank/concrete interface.

2. If the portion of the tank exposed to concrete is susceptible to an aging effect requiring management, provide applicable revised LRA sections.

Waterford 3 Response

1. The carbon steel tanks exposed to concrete in LRA Table 3.3.2-7 are the fuel oil storage tanks The bottoms of the tanks are approximately two feet above the floor resting on concrete pedestals. The pedestals are reinforced concrete cylinders filled with sand. There is a grout seal between the pedestals and the outer perimeters of the tanks. Each tank room has a sump with an automatic sump pump to maintain acceptable sump levels. Any water that leaks into the rooms housing the fuel oil storage tanks runs to the sumps preventing accumulation in the rooms to a level that could reach the tank bottoms.

Potential sources of water near the tanks are leakage from fire hose stations outside the entrances to the rooms and leakage through penetration seals for piping penetrations into the room. No penetrations have been identified through the fuel oil storage tank room ceiling that are located above the tanks. A search of the corrective action program database identified one occurrence of leakage of water into the room during a period of heavy rainfall. The source of the water appeared to be a piping penetration near the southwest corner of the west fuel oil storage tank room. The water dripped onto the floor near the sump in the corner of the room. The documentation for the condition did not indicate that water had dripped onto the tank.

2. The portions of the tanks exposed to concrete are not susceptible to aging effects requiring management.

RAI 4.3.3.2-a

Background:

By letter dated October 12, 2016, the staff issued RAI 4.3.3-2, requesting the applicant to provide additional information on its methodology to identify and evaluate plant-specific locations for environmentally-assisted fatigue (EAF). By letter dated December 12, 2016, the applicant responded to RAI 4.3.3-2 stating that its methodology will be based on EPRI Report 1024995, "Environmentally Assisted Fatigue Screening, Process and Technical Basis for Identifying EAF Limiting Locations." The applicant stated that this screening process will determine the "sentinel" locations that will bound and appropriately represent each thermal zone.

Issue:

EPRI Technical Report 1024995 has not been submitted to the NRC for approval and has not been endorsed by the NRC. The applicant did not define a plant-specific methodology and criteria used to select the most limiting locations for EAF. The licensee has not demonstrated that a plant-specific screen methodology has been developed in a manner that conservatively evaluates EAF effects, with the same degree of analytical rigor for all locations, to identify the bounding locations.

The applicant also did not provide information on the plant-specific criteria for each step of the applicant's plant-specific methodology. If evaluating locations on a representative sampling basis, the applicant did not provide the plant-specific criteria that adequately addresses:

1) how components will be grouped together within zones
2) how components will be assessed similarly (e.g., amount of rigor in calculating environmentally-adjusted cumulative usage factors, bounding components of differing materials, use of the same ASME Code Section III, Appendix I fatigue curves)
3) the systematic process to eliminate locations from consideration for EAF

Request:

1. Describe the plant-specific methodology that will be used to determine the limiting locations for EAF.

2. For each step of the methodology, describe and justify the plant-specific criteria, engineering judgement, assumptions, and relevant factors for each step of the process, such as thermal zones, material types, transient complexity, temperature effects, and complexity of the systems (as applicable). Justify that the process is appropriately conservative.

Waterford 3 Response

During a teleconference held on 3/13/17 between the NRC staff and Entergy, the NRC staff indicated that RAI 4.3.3-2a will be re-issued to Entergy with additional detail clarifying the information requested.

<u>RAI 4.3.1.2-a</u>

<u>Background:</u>

In RAI 4.3.1-2 the NRC requested clarification regarding which transients are used for the Leak Before Break (LBB) TLAA and justification that the transients are in the scope of the Fatigue Monitoring Program. The RAI response included a list of transients used in the analysis as well as justification for transients that are not used. The response indicated that the loss of secondary pressure transient is a Level C (Emergency) transient that does not need to be monitored under implementation of applicant's Fatigue Monitoring Program (LRA AMP B.1.11). The applicant stated that this transient does not need to be monitored because the provisions in ASME Code, Section III, sub-paragraph NB-3224.5 allow it to be excluded from any cumulative usage factor analyses for the piping components.
Technical Specifications (TS) Section 6.5.5, "Component Cyclic or Transient Limit," requires the applicant to track any design basis transients for Class 1 piping components, as defined in Technical Requirements Manual (TRM) Section 5.7. Specifically, TS Section 6.5.5 states that the "Component Cyclic or Transient Limit" Program "provides controls to track Technical Requirements Manual Section 5.7 cyclic and transient occurrences to ensure that components are maintained within the design limits."

<u>Issue</u>:

The scope of the exclusion provisions for service loading C transients in ASME Code, Section III, sub-paragraph NB-3224.5 appears to apply only to those cumulative fatigue analyses (i.e., cyclical loading analyses) that may be required to be performed in accordance with the requirements of ASME Code, Section III, sub-paragraph NB 3222.4. The Code does not identify that the provisions in Sub-paragraph NB 3224.5 may be applied to transients that are assumed in LBB analyses approved in the current licensing basis. The reason for this is that LBB analyses are submitted for NRC approval in accordance with the reporting requirements in 10 CFR Part 50, Appendix A, General Design Criterion 4, "*Dynamic Effects,*" and not per any reporting requirements in 10 CFR 50.55a or in Section III of the ASME Boiler and Pressure Vessel Code, Division 1.
In addition, WF3 TRM Section 5.7, "Component Cyclic or Transient Limits," states "the components identified in [TRM Table 5.7-1, "Component Cyclic or Transient Limits,"] are designed and shall be maintained within the cyclic or transient limits of Table 5.7-1." TRM Table 5.7-1 lists the loss of secondary pressure transient as a design basis transient that is required to be monitored in accordance with the requirements in TS Section 6.5.5. Thus, it appears that monitoring this design basis transient would be required by the TS requirements even if the transient would be permitted by ASME Sub-paragraph NB-3224.5 to be excluded from the scope of cumulative usage factor analyses for the Class 1 piping components.

<u>Request:</u>

Provide clarification and justification for the discrepancy that the loss of secondary pressure transient is included in TRM Table 5.7, but is not included in the Fatigue Monitoring Program.

Waterford 3 Response

WF3 will add the loss of secondary pressure transient to the transients that are tracked in the Fatigue Monitoring Program. A new row is added to LRA Table 4.3-1 to reflect this addition. Additions are underlined.

Table 4.3-1
Projected and Analyzed Transient Cycles

Transient Description	Number of Cycles as of 4/5/14	60-year Projected Number of Cycles[(a)]	Analyzed Number of Cycles
Loss of Secondary Pressure	0	3[b]	5

a. The original operating license term ends on 12/18/2024 and the renewed operating license term would end on 12/18/2044. The 4/5/2014 data date is at 29.3 years of operation. Unless otherwise identified by a footnote, the projected values are determined by using a multiplier of 60/29.3 = 2.05 times the number of occurrences as of 4/5/2014.

b. Although none of these cycles have occurred, a projected value is conservatively listed. These projected values have not been used to replace the original analyzed numbers of cycles. Cycles will continue to be tracked by the Fatigue Monitoring Program (Section B.1.11).

<u>RAI 3.1.1.88-1a</u>

<u>Background</u>:

By letter dated November 7, 2016 (ADAMS Accession No. ML16307A007), the U.S. Nuclear Regulatory Commission (NRC) staff requested additional information from the applicant regarding aging management of loss of material due to boric acid corrosion in steam generator channel heads and tubesheets. In addition, the November 7 letter also informed the licensee that License Renewal Interim Staff Guidance (LR-ISG)-2016-01 was being finalized. By letter dated December 7, 2016 (ADAMS Accession No. ML16342C491), the applicant submitted a response to the request for additional information. On December 7, 2016 (ADAMS Accession No. ML16237A383), the NRC staff also issued License Renewal Interim Staff Guidance (LR-ISG) 2016-01, "Changes to Aging Management Guidance for Various Steam Generator Components."

<u>Issue</u>:

The staff noted the following inconsistencies between the applicant's response and the guidance in LR-ISG-2016-01:

(a) In LR-ISG-2016-01, generic aging lessons learned (GALL) Report AMR items IV.D1.RP-367 and IV.D1.RP-385 were revised to include XI.M19 "Steam Generators" as the program to manage cracking due to primary water stress corrosion cracking (PWSCC) for divider plates and tube-to-tubesheet welds. In License Renewal Application (LRA) Table 3.1.2-4, as revised in the applicant's response, LRA AMR items associated with these GALL Report AMR items do not include the Steam Generator Integrity Program to manage the aging effect. This omission is inconsistent with the applicant's response stating "that the Steam Generator Integrity Program will manage loss of material of the steam generator channel heads and tubesheet and will manage cracking of the steam generator partition plate and tube-to-tubesheet welds."

The staff noted the following inconsistencies between the applicant's response and the guidance in LR-ISG-2016-01:

(a) In LR-ISG-2016-01, generic aging lessons learned (GALL) Report AMR items IV.D1.RP-367 and IV.D1.RP-385 were revised to include XI.M19 "Steam Generators" as the program to manage cracking due to primary water stress corrosion cracking (PWSCC) for divider plates and tube-to-tubesheet welds. In License Renewal Application (LRA) Table 3.1.2-4, as revised in the applicant's response, LRA AMR items associated with these GALL Report AMR items do not include the Steam Generator Integrity Program to manage the aging effect. This omission is inconsistent with the applicant's response stating "that the Steam Generator Integrity Program will manage loss of material of the steam generator channel heads and tubesheet and will manage cracking of the steam generator partition plate and tube-to-tubesheet welds."

(b) In conjunction with item (a) above, LRA Table 3.1.1, item 3.1.1-25 does not identify the Steam Generator Integrity Program as an aging management program used to manage cracking due to PWSCC for divider plate assemblies and tube-to-tubesheet welds. In comparison, the revised SRP-LR Table 3.1-1, ID 25 in LR-ISG-2016-01 lists GALL Report AMP XI.M2, "Water Chemistry" and AMP XI.M19, "Steam Generators" as existing aging management programs to manage the aging effect.

(c) LRA Table 3.1.2-4 includes AMR items associated with LRA item 3.1.1-88 to manage loss of material due to pitting and crevice corrosion for steam generator channel heads and tubesheets. However, LRA Table 3.1.2-4 does not identify AMR items to manage loss of material due to boric acid corrosion using the Steam Generator Integrity Program to manage this aging effect. In contrast, LR-ISG-2016 recommends use of SRP-LR Table 3.1-1 ID 127a and GALL Report AMR item IV.D1.R-436a to manage the aging effect for these components. This omission is also inconsistent with the applicant's response stating "that the Steam Generator Integrity Program will manage loss of material of the steam generator channel heads and tubesheet and will manage cracking of the steam generator partition plate and tube-to-tubesheet welds."

(d) In conjunction with item (c) above, LRA Table 3.1.1 does not include SRP-LR Table 3.1-1, ID 127a (as revised in LR-ISG-2016-01) which manages loss of material due to boric acid corrosion for steam generator channel heads and tubesheets using GALL Report AMPs XI.M19, "Steam Generators" and XI.M2, "Water Chemistry."

Request:

Please resolve these inconsistencies with LR-ISG-2016-01 or justify their acceptability.

Waterford 3 Response

(a) As described in the response to RAI 3.1.1.88-1 dated December 7, 2016 (ADAMS Accession No. ML16342C491), the Waterford 3 steam generator partition plates (divider plates) and tube-to-tubesheet welds are made of Alloy 690 which is resistant to primary water stress corrosion cracking. Consequently, Entergy credited the Water Chemistry Control – Primary and Secondary Program with its associated One-Time Inspection Program to manage cracking. The inconsistency identified in part (a) of the issue resulted from the inadvertent inclusion in the Waterford 3 response to RAI 3.1.1.88-1 of the statement that the Steam Generator Integrity Program will manage cracking of the steam generator partition plate and tube-to-tubesheet welds. The general visual inspections of the partition plate and tubesheet recommended in LR-ISG-2016-01 were added to the Steam Generator Integrity Program in the response to RAI 3.1.1.88-1. However, because the detection of cracking due to PWSCC is not feasible with visual inspections, the Steam Generator Integrity Program was not credited to manage cracking. As indicated in the response to RAI 3.1.1.88-1, the visual inspections will verify no rust stains, discoloration, or distortion of the cladding that could indicate loss of material due to boric acid corrosion of base metals resulting from a breach of the cladding.

(b) As described in the response to RAI 3.1.1.88-1 dated December 7, 2016 (ADAMS Accession No. ML16342C491), the Waterford 3 steam generator partition plates (divider plates) and tube-to-tubesheet welds are made of Alloy 690 which is resistant to primary water stress corrosion cracking. Consequently, Entergy credited the Water Chemistry Control – Primary and Secondary Program with its associated One-Time Inspection Program to manage cracking. Because the detection of cracking due to PWSCC is not feasible with visual inspections, the Steam Generator Integrity Program was not added to LRA Table 3.1.1, item 3.1.1-25. However, as indicated in the response to RAI 3.1.1.88-1, the visual inspections added to the Steam Generator Integrity Program will verify no rust stains, discoloration, or distortion of the cladding that could indicate loss of material due to boric acid corrosion of base metals resulting from a breach of the cladding.

(c) A change to Table 3.1.2-4 was omitted in the response to RAI 3.1.1.88-1 dated December 7, 2016. LRA Table 3.1.2-4 is revised to include new line items that specify that the Steam Generator Integrity Program and Water Chemistry Control – Primary and Secondary Program manages loss of material due to boric acid corrosion of the steam generator channel head and tubesheet. The Steam Generator Integrity Program manages this aging effect using visual inspection as described in the response to RAI 3.1.1.88-1.

(d) The intent of the SRP-LR Table 3.1-1, ID 127a recommendation is met by the revision to LRA Table 3.1.2-4 described in response (c) above.

LRA revisions are shown below. Additions are shown with underline and deletions are shown with strikethrough.

Table 3.1.2-4
Steam Generators
Summary of Aging Management Evaluation

Table 3.1.2-4: Steam Generators

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Tubesheet	Pressure boundary	Carbon steel clad with nickel alloy (Alloy 690)	Treated borated water (int)	Loss of material	Steam Generator Integrity Water Chemistry Control – Primary and Secondary	--	--	H, 106
Channel head	Pressure boundary	Carbon steel clad with stainless steel or nickel alloy (Alloy 690)	Treated borated water > 140°F (int)	Loss of material	Steam Generator Integrity Water Chemistry Control – Primary and Secondary	--	--	H, 106

Notes for Table 3.1.2-1 through Table 3.1.2-5-2

Plant-Specific Notes

106. The Steam Generator Integrity Program, in conjunction with the Water Chemistry Control – Primary and Secondary Program, will manage the aging effect of loss of material due to boric acid corrosion of the steam generator channel head and tubesheet.

RAI B.1.37-1a

Background:

By letter dated December 7, 2016, the applicant responded to RAI B.1.37-1 to address guidance updates for GALL Report AMP XI.M19, "Steam Generators." In its response, the applicant identified a program enhancement that will revise the Steam Generator Integrity Program to include general visual inspection of the partition plate, channel head, and tubesheet (primary side). The applicant also stated that the LRA is revised to indicate that the Steam Generator Integrity Program will include a general visual inspection of the steam generator tubesheet cladding each time the steam generator manway is opened for inspections.

On December 7, 2016, the NRC staff issued the final License Renewal Interim Staff Guidance (LR-ISG)-2016-01, "Changes to Aging Management Guidance for Various Steam Generator Components" (ADAMS Accession No. ML16237A383), which includes the following guidance:

- Visual inspections on steam generator head internal areas (head interior surfaces, divider plate assemblies, tubesheets (primary side), and tube-to-tubesheet welds) in order to identify signs of cracking or loss of material (e.g., rust stains and distortion of divider plates)
- Frequency of visual inspections: at least every 72 effective full power months or every third refueling outage, whichever results in more frequent inspections
- Implementation of the Electric Power Research Institute (EPRI) steam generator guidelines such as (a) EPRI Report 1022832 (Primary-to-Secondary Leak Guidelines); (b) EPRI Report 1025132 (In-Situ Pressure Test Guidelines); (c) EPRI Report 3002007571 (Integrity Assessment Guidelines); and (d) EPRI Report 3002007572 (Examination Guidelines).

Issue:

It is unclear whether the applicant's Steam Generator Integrity Program is consistent with the guidance discussed above.

Request:

1. Clarify whether the visual inspection frequency for the channel head internal areas (i.e., each time the steam generator manway is opened) meets the guidance in LR-ISG-2016-01 (i.e., at least every 72 effective full power months or every third refueling outage, whichever results in more frequent inspections). If not, justify the inspection frequency.

2. The FSAR supplement (LRA Section A.1.37) and program description (LRA Section B.1.37) does not include the frequency of visual inspections as described in LR-ISG-2016-01. Please justify these omissions.

3. Please discuss the implementation of or plans to implement the EPRI steam generator guidelines by the implementation dates provided by the industry.

<u>Waterford 3 Response</u>

1. The channel head internal areas are visually inspected at least once every 72 effective full power months or every third refueling outage, whichever results in more frequent inspections. The program description is revised to specify this frequency as shown below. Additions are underlined and deletions are lined through.

2. The FSAR supplement (LRA Section A.1.37) and program descriptions (LRA Section B.1.37) are revised to specify the visual inspection frequency for the channel head internal areas. Additions are underlined and deletions are lined through.

3. Waterford 3 has implemented EPRI steam generator guidelines, including revisions to EPRI Steam Generator Management Program (SGMP) documents, any interim guidance provided by the SGMP, and SGMP administrative procedures. Deviations to "Mandatory" or "Needed" elements of an approved SGMP guideline are documented and NRC Staff notified. Deviations to "Good Practice" elements of an approved SGMP guideline are evaluated in accordance with station procedures.

A.1.37 Steam Generator Integrity Program

The Steam Generator Integrity Program manages aging effects for the steam generator tubes, plugs, sleeves, and secondary side components contained within the steam generator in accordance with the plant technical specifications and commitments to NEI 97-06. Preventive and mitigative measures include foreign material exclusion programs and other primary and secondary side maintenance activities, such as sludge lancing and inspecting any installed plugs and replacing them when needed with updated materials as needed. The program has acceptance criteria for when a tube should be plugged based on wall thickness measurements.

Steam generator water chemistry is monitored and maintained in accordance with the Water Chemistry Control - Primary and Secondary Program. The thermally treated Alloy 690 tubes are monitored for wear based on industry experience using inspection techniques capable of detecting the aging effect. The general conditions of components (e.g., plugs when installed, sleeves, tubesheet primary side, channel head surfaces exposed to reactor coolant, partition plate, and secondary side components) are monitored visually. <u>Visual Inspections of primary side components are performed at least once every 72 effective full power months or every third refueling outage, whichever results in more frequent inspections, and</u> will verify no rust stains, discoloration, or distortion of the cladding that could indicate loss of material due to boric acid corrosion of base metals resulting from a breach of the cladding.

B.1.37 Steam Generator Integrity

Program Description

The Steam Generator Integrity Program manages aging effects for the steam generator tubes, plugs, sleeves, and secondary side components contained within the steam generator in accordance with the plant technical specifications and commitments to NEI 97-06. Preventive and mitigative measures include foreign material exclusion programs and other primary and secondary side maintenance activities, such as sludge lancing and inspecting any installed plugs and replacing them with updated materials as needed. The program has acceptance criteria for when a tube should be plugged based on wall thickness measurements.

Steam generator water chemistry is monitored and maintained in accordance with the Water Chemistry Control – Primary and Secondary Program. The thermally treated Alloy 690 tubes are monitored for wear based on industry experience using inspection techniques capable of detecting the aging effect. The general conditions of components (e.g., plugs when installed, sleeves, tubesheet primary side, channel head surfaces exposed to reactor coolant, partition plate, and secondary side components) are monitored visually. Visual Inspections of primary side components are performed at least once every 72 effective full power months or every third refueling outage, whichever results in more frequent inspections, and will verify no rust stains, discoloration, or distortion of the cladding that could indicate loss of material due to boric acid corrosion of base metals resulting from a breach of the cladding.

Enhancements

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

Element Affected	Enhancement
4. Detection of Aging Effects	Revise the Steam Generator Integrity Program to include general visual inspection of the partition plate, channel head, and tubesheet (primary side) with a frequency of at least once every 72 effective full power months or every third refueling outage, whichever results in more frequent inspections.

Enclosure 2 to

W3F1-2017-0015

RAI B.1.28-2 and RAI 3.5.1.79-1 Revised Responses
Waterford 3 License Renewal Application

RAI B.1.28-2(Revised)

Background:

LRA Section B.1.28, "One-Time Inspection," notes that the program will be used to verify that change in material properties, loss of material and cracking are not occurring for reinforced concrete portions of the circulating water intake piping exposed to raw water.

During the audit, the staff reviewed a summary report prepared by Pure Technologies US, Inc. of a previous inspection conducted on similar concrete piping in a 132-inch cooling water discharge line. The summary report of the Pure Technologies US, Inc. inspection noted that a majority of the pipe joints exhibited separation and/or spalling and recommended all pipeline joints be cleaned and mortared to prevent corrosion of the joint steel and potential leaks. The report also recommended a re-inspection of the pipeline in approximately five years.

The “Program Description” and “Scope of Program” of GALL Report AMP XI.M32 “One-Time Inspection” states, in part: “This program cannot be used for structures or components with known age-related degradation mechanisms or when the environment in the period of extended operation is not expected to be equivalent to that in the prior 40 years. Periodic inspections should be proposed in these cases.”

Issue:

The GALL Report includes AMR line items for concrete piping exposed to raw water and recommends XI.M20, “Open-Cycle Cooling Water System,” for managing the effects of aging. GALL Report AMP XI.M20 recommends periodic inspections. In addition, the Pure Technologies report recommended a follow-up inspection of similar piping in approximately five years.

Based on the GALL Report recommendation in AMPs XI.M20 and XI.M32 that periodic inspections should be proposed for structures or components with known age-related degradation mechanisms, and the recommendations in the Pure Technologies report for addressing observed degradation mechanism(s), it is unclear to the staff why a one-time inspection is appropriate to manage the effects of aging for concrete piping in the circulating water system. The staff also needs additional information to determine whether the applicant’s operating experience supports the sufficiency of the LRA AMP.

Request:

Explain why it is appropriate to manage the effects of aging on concrete portions of the circulating water intake piping exposed to raw water via the one-time inspection program. The response should consider the guidance in the GALL Report AMPs for similar material and environment combinations and the operating experience described in the Pure Technologies report, specifically the recommendation to re-inspect the piping.

<u>Waterford 3 Response</u>

Based on results of previous inspection, Entergy has concluded that the One-Time Inspection Program is not the most appropriate program to manage the effects of aging on concrete portions of the circulating water intake piping exposed to raw water. The Periodic Surveillance and Preventive Maintenance Program will be credited to manage the effects of aging on this piping. Inspections under the Periodic Surveillance and Preventive Maintenance Program will occur at least once every ten years during the period of extended operation. A frequency of once every ten years is appropriate based on the following factors.

- The normal operating pressure in the circulating water intake piping is low.
- The circulating water intake piping serves a license renewal intended function only in the event of a tornado that requires makeup from the circulating water system to the auxiliary component cooling water wet cooling tower basins
- The interior of the piping is normally inaccessible. Access requires entry through a water box of the main condenser.
- The condition of the reinforced concrete piping was generally good.

The first inspection of the reinforced concrete piping will be performed prior to the period of extended operation.

LRA revisions are as follows. Additions are underlined and deletions are lined through.

LRA Sections and Tables Affected

Table 3.3.1: Auxiliary Systems
Table 3.3.2-3: Component Cooling and Auxiliary Component Cooling Water System Summary of Aging Management Evaluation
A.1.28 One-Time Inspection Program
A.1.30 Periodic Surveillance and Preventive Maintenance Program
B.1.28 One-Time Inspection
B.1.30 Periodic Surveillance and Preventive Maintenance

Table 3.3.1: Auxiliary Systems					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.3.1-30	Concrete; cementitious material piping, piping components, and piping elements exposed to raw water	Changes to material properties due to aggressive chemical attack	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	The nonsafety-related concrete circulating water intake piping (included in scope for a rare tornado event) is designed and constructed to AWWA C-300, -301, -302 requirements resulting in dense, well-cured high strength concrete with low permeability. The pipe is exposed to raw water (river water) that is not aggressive. Consequently, changes in material properties is not a significant aging effect for the piping. Nevertheless, the ~~One-Time Inspection~~ <u>Periodic Surveillance and Preventive Maintenance</u> Program will confirm that unacceptable degradation is not occurring.

3.3.1-31	Concrete; cementitious material piping, piping components, and piping elements exposed to raw water	Cracking due to settling	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	The nonsafety-related concrete circulating water intake piping is included in scope for a rare tornado event. Bedding under this piping conforms to Class A or Class C as specified by the American Concrete Pipe Association which provides a densely compacted backfill limiting the potential for settlement leading to cracking of the concrete piping. Consequently, cracking of the piping due to settling is not a significant aging effect for the piping. This is consistent with NUREG-1800, Table 3.3.1, which does not identify cracking due to settling for reinforced concrete piping. Nevertheless, the ~~One-Time Inspection~~ Periodic Surveillance and Preventive Maintenance Program will confirm that unacceptable degradation is not occurring.
3.3.1-32	Reinforced concrete, asbestos cement piping, piping components, and piping elements exposed to raw water	Cracking due to aggressive chemical attack and leaching; Changes in material properties due to aggressive chemical attack	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	The nonsafety-related concrete circulating water intake piping (included in scope for a rare tornado event) is designed and constructed to AWWA C-300, -301, -302 requirements resulting in dense, well-cured high strength concrete with low permeability. The pipe is exposed to raw water (river water) that is not aggressive. Consequently, cracking and changes in material properties are not significant aging effects for the piping. Nevertheless, the ~~One-Time Inspection~~ Periodic Surveillance and Preventive Maintenance Program will confirm that unacceptable degradation is not occurring.

3.3.1-33	Concrete; cementitious material piping, piping components, and piping elements exposed to raw water	Loss of material due to abrasion, cavitation, aggressive chemical attack, and leaching	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	The nonsafety-related concrete circulating water intake piping (included in scope for a rare tornado event) is designed and constructed to AWWA C-300, -301, -302 requirements resulting in dense, well-cured high strength concrete with low permeability. The pipe is exposed to raw water (river water) that is not aggressive. Consequently, loss of material is not a significant aging effect for the piping. Nevertheless, the ~~One-Time Inspection~~ Periodic Surveillance and Preventive Maintenance Program will confirm that unacceptable degradation is not occurring.

Table 3.3.2-3
Component Cooling and Auxiliary Component Cooling Water System
Summary of Aging Management Evaluation

Table 3.3.2-3: Component Cooling and Auxiliary Component Cooling Water System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Piping	Pressure boundary	Concrete	Raw water (int)	Change in material properties	Periodic Surveillance and Preventive Maintenance ~~One-Time Inspection~~	VII.C1.A P-250 VII.C1.A P-155	3.3.1-30 3.3.1-32	E
Piping	Pressure boundary	Concrete	Raw water (int)	Cracking	Periodic Surveillance and Preventive Maintenance ~~One-Time Inspection~~	VII.C1.A P-248 VII.C1.A P-155	3.3.1-31 3.3.1-32	E
Piping	Pressure boundary	Concrete	Raw water (int)	Loss of material	Periodic Surveillance and Preventive Maintenance ~~One-Time Inspection~~	VII.C1.A P-249	3.3.1-33	E

A.1.28 One-Time Inspection Program

~~CW intake piping internals (reinforced concrete portions)~~	~~One-time inspection activity will confirm that change in material properties, loss of material, and cracking are not occurring or are occurring so slowly that they will not affect the component intended function during the period of extended operation.~~

A.1.30 Periodic Surveillance and Preventive Maintenance Program

The Periodic Surveillance and Preventive Maintenance (PSPM) Program manages aging effects not managed by other aging management programs, including change in material properties, cracking, loss of material, and reduction of heat transfer.

Inspections occur at least once every 5 years during the period of extended operation, except for inspection of the circulating water intake piping. Inspection of the internal surface of the nonsafety-related concrete circulating water intake piping occurs at least once every 10 years with the first inspection prior to the period of extended operation.

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

- Inspect submersible sump pumps and backup pumps for dry cooling towers.
- Inspect emergency diesel generator system heat exchanger tubes.
- Inspect internal surface of stainless steel expansion joint in diesel exhaust.
- Inspect tubes and fins of the CCW dry cooling tower radiator.
- Inspect the internal surface of the portable UHS replenishment pump casing.
- Inspect the circulating water intake piping internal surface (reinforced concrete portions)
- Inspect the inside surface of RCP oil collection components (drip pans, enclosures, flame arrestors (tail pipe), piping, sight glass, tanks, and valve bodies).
- Inspect internal and external surfaces of control room HVAC portable smoke removal fan and smoke-ejector duct.

B.1.28 One-Time Inspection

Program Description

~~Circulating water intake piping (reinforced concrete portions)~~	~~One-time inspection activity will confirm that change in material properties, loss of material and cracking are not occurring or are occurring so slowly that they will not affect the component intended function during the period of extended operation.~~

B.1.30 Periodic Surveillance and Preventive Maintenance

Program Description

There is no corresponding NUREG-1801 program.

The Periodic Surveillance and Preventive Maintenance (PSPM) Program includes periodic inspections and tests to manage aging effects not managed by other aging management programs, including change in material properties, cracking, loss of material, and reduction of heat transfer.

Inspections occur at least once every 5 years during the period of extended operation, except for inspection of the circulating water intake piping. Inspection of the internal surface of the nonsafety-related concrete circulating water intake piping occurs at least once every 10 years with the first inspection prior to the period of extended operation.

Credit for program activities has been taken in the aging management review of systems, structures and components as described below.

System	**Inspection**
Plant drains	Perform a visual inspection of the surface condition of a representative sample of the submersible sump pumps and the back-up pumps for the dry cooling towers.
Emergency generator system	Perform a visual inspection of the surface condition of a representative sample of EDG cooler heat exchanger tubes to manage loss of material due to wear. Monitor the surface condition of the expansion joint to verify the absence of cracking due to stress corrosion/IGA.
Circulating water intake piping (reinforced concrete portions)	Perform visual inspection of the internal surface of the concrete piping to confirm that unacceptable degradation due to the effects of aging is not occurring.
Component cooling and auxiliary component cooling water system	Use visual or other NDE techniques to inspect a representative sample of the tubes and fins of the CCW dry cooling tower radiator to manage loss of material and fouling that could result in a reduction of heat transfer capability. Perform a visual inspection of the internal surface of the portable UHS replenishment pump casing to manage loss of material.
RCP oil collection (RCPOC)	Visually inspect the inside surface of RCP oil collection components (representative samples) in an environment of waste lube oil to manage loss of material.

Evaluation

3. Parameters Monitored/Inspected

The Periodic Surveillance and Preventive Maintenance Program monitors and inspects parameters linked to the degradation of the particular structure or component. For example, surface conditions of metallic components are monitored for loss of material, fouling that could result in a reduction of heat transfer capability, cracking, and worn or flaking surfaces, while polymeric components are inspected for cracking, crazing, scuffing, dimensional changes, discoloration and hardening as evidenced by loss of suppleness.

For selected <u>metallic</u> piping components, wall thickness is measured to determine the extent of corrosion caused by recurring internal corrosion mechanisms. <u>For reinforced concrete piping, visual inspections monitor the condition of the internal surface.</u>

4. Detection of Aging Effects

Periodic surveillance and preventive maintenance activities provide for periodic component inspections and testing to detect aging effects. Inspection and test intervals are established such that they provide timely detection of degradation prior to loss of intended functions. Inspection and test intervals, sample sizes, and data collection methods are dependent on component material and environment, biased toward locations most susceptible to aging, and derived with consideration of industry and plant-specific operating experience and manufacturers' recommendations.

Established techniques such as visual inspections are used. Each inspection or test occurs at least once every 5 years, <u>except for inspection of the circulating water intake piping</u>. <u>Inspection of the internal surface of the nonsafety-related concrete circulating water intake piping occurs at least once every 10 years with the first inspection prior to the period of extended operation.</u> Inspections are performed by personnel qualified to perform the selected technique.

For each activity listed above that refers to a representative sample, a representative sample is 20 percent of the population (defined as components having the same material, environment, and aging effect combination) with a maximum of 25 components.

RAI 3.5.1.79-1

Background

Section 54.21(a)(3) of 10 CFR requires the applicant to demonstrate that the effects of aging for structures and components will be adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis for the period of extended operation. As described in SRP-LR, an applicant may demonstrate compliance with 10 CFR 54.21(a)(3) by referencing the GALL Report and when evaluation of the matter in the GALL Report applies to the plant.

SRP-LR Table 3.5-1, item 79, recommends that steel piles exposed to a groundwater/soil environment be managed for loss of material due to corrosion by the Structures Monitoring Program. Per the SRP-LR, this line item is associated with GALL Report item III.A3.TP-219 for structures and components supports.

LRA Table 2.4-3 lists the steel piles component as subject to aging management review with an intended function to support criterion (a)(3) equipment. LRA Table 3.5.1, item 3.5.1-79 states that steel piles exposed to groundwater and/or soil is not applicable because WF3 has no steel piles subject to the listed aging effects. However, LRA Table 3.5.2-3 identifies one AMR item associated with steel piles exposed to soil as having no aging effects requiring management. This AMR item cites generic note I to state that this aging effect in the GALL Report is not applicable, and plant-specific note 501, page 3.5-49, which states:

> *"Steel piles driven into undisturbed soils are unaffected by corrosion. Where steel piles are driven into disturbed soils, operating experience has shown that only minor to moderate corrosion has occurred that would not significantly affect the performance of the component intended function during the license renewal term. The steel piles are steel casings used as forms for the concrete inside the steel piles. The concrete inside the steel casing is not susceptible to degradation that could impair the ability of the concrete to perform its intended function. Therefore, no aging management is required."*

Issue:

The staff noted inconsistencies between the AMR line item associated with steel piles in LRA Table 3.5.2-3, the LRA disposition of Table 3.5.1 item 3.5.1-79, and the intended function identified in LRA Table 2.4-3. LRA Table 2.4.3 dispositions the steel piles as having an intended function of support for Criterion 10 CFR 54.4(a)(3) equipment; LRA Table 3.5.1, item 3.5.1-79 states that WF3 has no steel piles subject to the loss of material due to corrosion aging effect; and plant-specific note number 501 from LRA Table 3.5.2-3 identifies the steel piles as experiencing an aging effect of minor to moderate corrosion but dispositions them as not requiring aging management due to being steel casings that are used as forms for the concrete (which is not susceptible to degradation) inside the steel piles. The staff also noted that plant-specific note number 501 does not provide a technical basis (e.g. analysis of degradation rate and expected degradation during the period of extended operation) to support the conclusion that "no aging management is required" for steel piles with ongoing corrosion or for the concrete inside the steel casings.

Based on the information provided in the LRA, the staff is not clear (1) whether the steel piles or steel casing are within the scope of license renewal, and (2) whether the AMR line item in LRA Table 3.5.2-3 and associated line item 3.5.1-79 in LRA Table 3.5.1, are consistent with the GALL Report recommendation from line item III.A3.TP-219 to ensure that the aging effects of loss of material due to corrosion is adequately managed for the period of extended operation.

<u>Request</u>:

1. Clarify if steel piles or steel casings are within the scope of license renewal and the intended function that needs to be maintained during the period of extended operation.
2. If steel piles are within the scope of license renewal, describe how the aging effects of loss of material due to corrosion in steel piles exposed to a groundwater/soil environment will be adequately managed so that the intended function will be maintained consistent with the current licensing basis for the period of extended operation. Otherwise, provide the technical justification for the exception to the GALL Report recommendation.
3. Clarify any inconsistency between LRA Table 3.5.1, item 3.5.1-79, and LRA Table 3.5.2-3 line item associated with steel piles to be consistent with the response to the above request.

<u>Waterford 3 Response</u>

1. The steel piles (or casings) associated with the fire water storage tanks foundation, are within the scope of license renewal and subject to aging management review as identified in Waterford 3 (WF3) license renewal application (LRA) Table 2.4-3 and Table 3.5.2-3 to provide structural support of the fire water tanks, which are in-scope for fire protection in accordance with 10 CFR 54.4(a)(3).

2. The WF3 steel piles (or casings) are within the scope of license renewal as discussed in response to part 1 above. As shown in the LRA Table 2.4-3 the steel casings are subject to aging management review. Inspections of the fire water tanks and their foundations will be able to detect potential degradation, if any, in the tank foundation that degraded steel piles (or casings) might cause (e.g., settlement). However, as shown in LRA Table 3.5.2-3 and associated note 501, the pilings do not have aging effects requiring management. The steel casings are closed end, steel pipes filled with concrete and strong enough to withstand ground pressure without buckling or collapsing having a wall thickness of 3/8 inch. These piles have a minimum diameter of 12 inches and are driven, closed end first, into undisturbed ground. FSAR Figure 1.2 1 shows that the tanks are located several hundred feet southwest of the turbine building and are not impacted by ground preparations associated with the turbine building construction, which could lead to the soil in this area becoming disturbed by construction activities. Industry operating experience, reported in EPRI 1015078 “Plant Support Engineering: Aging Effects for Structures and Structural Components (Structural Tools)”, has shown that the type and amount of corrosion observed on steel pilings (or casings) driven into undisturbed natural soil, regardless of the soil characteristics and properties, is not sufficient to significantly affect the strength of pilings as load bearing structures. The data also indicate that undisturbed natural soils are so deficient in oxygen at levels a few feet below the surface, or below the water table, that steel piles are not appreciably affected by corrosion. Because steel piles driven in undisturbed soils have been shown to be unaffected by corrosion and those driven in disturbed soil have experienced only minor to moderate corrosion, loss of material due to corrosion is not an aging effect requiring management for steel piles. Industry operating experience has shown that the concrete inside steel piles is not susceptible to degradation that could impair the ability of the

concrete to perform its intended function because the strength capacity of the laterally constrained concrete is not sensitive to degradation of the steel casing. The WF3 in-scope steel pipe casings driven into the soil do not have aging effects requiring management for the PEO.

3. As discussed in responses to part 1 and 2 above, WF3 steel piles are in the scope of license renewal and subject to aging management review, but have no aging effects requiring management as shown in LRA Table 2.4-3, 3.5.2-3 and 3.5.1 item 79. However, LRA Table 3.5.1 item 3.5.1-79 discussion has been revised to provide additional clarification to show consistency with Tables 2.4-3 and 3.5.2-3.

LRA revisions are as follows. Additions are shown with underline and deletions with strikethrough.

` **Table 3.5.1: Structures and Component Supports**

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-79	Steel components: piles	Loss of material due to corrosion	Structures Monitoring Program	No	~~Not applicable. WF3 has no steel piles subject to the listed aging effect; therefore this line item was not used.~~ <u>WF3 in-scope steel piles are not subject to this aging effect. Industry operating experience has shown that steel piles driven in subgrade experience insignificant degradation and that loss of material due to corrosion is not an aging effect requiring management.</u>

Enclosure 3 to

W3F1-2017-0015

LRA Table 3.3.2-15-17 Correction
Waterford 3 License Renewal Application

LRA Table 3.3.2-15-17 Correction

In February 2017, an error was identified in the Waterford 3 License Renewal Application (LRA) related to components in the emergency diesel generator system. This error was documented in the corrective action process. LRA Table 3.3.2-15-17, Emergency Diesel Generator System Nonsafety-Related Components Affecting Safety-Related Systems Summary of Aging Management Evaluation, includes “piping” and “valve bodies” with an internal environment of lube oil. It was determined these components, instead, have an internal environment of air. No other piping or valves subject to aging management review under 10 CFR 54.4(a)(2) in this system contain lube oil; therefore LRA Table 3.3.2-15-17 is revised to change piping and valve bodies with an internal environment of lube oil to piping and valve bodies with an internal environment of indoor air.

Changes to LRA Table 3.3.2-15-17 follow with additions underlined and deletions lined through.

Table 3.3.2-15-17
Emergency Diesel Generator System
Nonsafety-Related Components Affecting Safety-Related Systems
Summary of Aging Management Evaluation

Table 3.3.2-15-17: Emergency Diesel Generator System, Nonsafety-Related Components Affecting Safety-Related Systems

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Piping	Pressure boundary	Carbon steel	~~Lube oil (int)~~ Air – indoor (int)	Loss of material	~~Oil Analysis~~ Internal Surfaces in Miscellaneous Piping and Ducting Components	~~VII.H2.AP-127~~ V.A.E-29	~~3.3.1-97~~ 3.2.1-44	~~A, 302~~ C
Valve body	Pressure boundary	Stainless steel	~~Lube oil (int)~~ Air – indoor (int)	~~Loss of material~~ None	~~Oil Analysis~~ None	~~VII.H2.AP-138~~ VII.J.AP-123	~~3.3.1-100~~ 3.3.1-120	~~A, 302~~ A