Entergy

Entergy Operations, Inc.
1340 Echelon Parkway
Jackson, MS 39213
Tel 601-368-5138

Ron Gaston
Director, Nuclear Licensing

10 CFR 50.90

GNRO-2020/00013

March 31, 2020

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

Subject: License Amendment Request for One-Cycle Extension of Appendix J Type A Integrated Leakage Rate Test and Drywell Bypass Leakage Rate Test

Grand Gulf Nuclear Station, Unit 1
NRC Docket No. 50-416
Renewed Facility Operating License No. NPF-29

References:

1) Entergy Operations, Inc. (Entergy) letter to U. S. Nuclear Regulatory Commission (NRC), "Grand Gulf Nuclear Station, Unit 1 – Issuance of Amendment [No. 214] Re: One Cycle Extension of Appendix J Type A Integrated Leakage Test and Drywell Bypass Test Interval (CAC No. MF9461; EPID L-2016-LLA-0040)," (ADAMS Accession No. ML17334A739), dated December 29, 2017

2) Entergy letter to NRC, "License Amendment Request for Permanent Extension of Appendix J Type A Integrated Leakage Rate Test Frequencies," (ADAMS Accession No. ML20050R656), dated February 19, 2020

In accordance with Title 10 of the Code of Federal Regulations (CFR) Part 50, Section 50.90, "Application for amendment of license, construction permit, or early site permit," Entergy Operations, Inc. (Entergy) is submitting a request for an amendment to Renewed Facility Operating License (FOL) NPF-29, Appendix A, "Technical Specifications" (TS) for Grand Gulf Nuclear Station, Unit 1 (GGNS). The proposed change would allow for a one-cycle extension of the interval to perform the the GGNS Type A integrated leakage rate test (ILRT) and drywell bypass leakage rate test (DWBT) from 11.5 years to 13.5 years. These tests, as specified in GGNS TS 5.5.12 "Containment Leakage Rate Testing Program," and TS Surveillance Requirement (SR) 3.6.5.1.1, respectively, are required to be performed prior to start-up following the current GGNS Refueling Outage 22 (RF22). The current ILRT and DWBT frequency requirement represents an extension of the frequency from 10 years to 11.5 years, which was approved by the NRC in Reference 1.

The proposed change would permit the ILRT and DWBT to be performed prior to start-up following GGNS RF23, which is scheduled to commence in February 2022. As such, the one-cycle extension of the ILRT and DWBT interval would represent a duration of approximately 13.5 years since the last performance of the ILRT and DWBT on October 19, 2008.

The proposed amendment is risk-informed and follows the guidance in RG 1.174, "An Approach For Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," Revision 2. By letter dated February 19, 2020 (Reference 2), Entergy submitted a license amendment request (LAR) to allow a permanent extension of the Type A ILRT interval to once every 15 years. As part of the permanent extension LAR, Entergy performed a GGNS-specific evaluation to assess the risk impact of a 15-year permanent ILRT extension. The proposed one-cycle extension requested in this LAR utilizes the GGNS-specific risk evaluation and the non-risk-based performance and testing information which were provided in the Reference 2 LAR. The GGNS-specific risk evaluation is also provided as an attachment to this LAR.

GGNS is currently scheduled to perform a Type A ILRT and DWBT (i.e., SR 3.6.5.1.1), prior to entering Operational MODE 2 (startup). The MODE change is scheduled to occur in mid-April. Based on a mid-April MODE change, the requested approval date of the proposed change to extend the ILRT and DWBT interval is less than the 30-day federal register public notice period specified in 10 CFR 50.91(a)(6). Therefore, Entergy requests approval of the proposed amendment on an exigent basis. Consistent with the requirements of 10 CFR 50.91(a)(6), Entergy believes that the need to minimize exposure of essential and non-essential personnel to the COVID-19 virus, and expeditiously return GGNS to service in support of the National Emergency Declaration could not have been avoided, and as such creates an exigent circumstance.

The enclosure to this letter provides a description and assessment of the proposed changes to the GGNS TS.

- Attachment 1 provides the existing TS pages marked up to show the proposed changes.
- Attachment 2 provides revised (clean) TS pages.
- Attachment 3 provides an evaluation of the risk significance of a 15-year permanent ILRT extension

Entergy requests approval of the proposed license amendment by April 15, 2020. The proposed changes would be implemented upon issuance of the amendment.

This letter contains no new regulatory commitments.

Should you have any questions or require additional information, please contact Ron Gaston, Director, Nuclear Licensing at 601-368-5138.

In accordance with 10 CFR 50.91, "Notice for public comment; State consultation," paragraph (b), a copy of this application, with attachments, is being provided to the designated State Officials.

I declare under penalty of perjury, the foregoing is true and correct. Executed on March 31, 2020.

Respectfully,

Ron Gaston

RWG/jls

Enclosure: Evaluation of the Proposed Change

Attachments to Enclosure:

1. Markup of Technical Specification Page
2. Retyped Technical Specification Page
3. Grand Gulf Nuclear Station: Evaluation of Risk Significance of Permanent ILRT Extension

cc: NRC Region IV Regional Administrator
NRC Senior Resident Inspector – Grand Gulf Nuclear Station, Unit 1
State Health Officer, Mississippi Department of Health
NRC Project Manager - Grand Gulf Nuclear Station, Unit 1

Enclosure

GNRO-2020/00013

Evaluation of the Proposed Change

Evaluation of the Proposed Change

Subject: License Amendment Request for One-Cycle Extension of Appendix J Type A Integrated Leakage Rate Test and Drywell Bypass Leakage Rate Test

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Attachments:
1. Markup of Technical Specification Pages
2. Retyped Technical Specifications Pages
3. Grand Gulf Nuclear Station: Evaluation of Risk Significance of Permanent ILRT Extension

1.0 SUMMARY DESCRIPTION

In accordance with 10 CFR 50.90, "Application for amendment of license, construction permit, or early site permit," Entergy Operations, Inc. (Entergy) requests an amendment to Renewed Facility Operating License (FOL) NPF-29, Appendix A, "Technical Specifications" (TS) for Grand Gulf Nuclear Station, Unit 1 (GGNS). The proposed change would allow for a one-cycle extension to perform the the GGNS integrated leakage rate test (ILRT) and drywell bypass leakage rate test (DWBT) from the current TS requirement of 11.5 years to 13.5 years.

These tests, as specified in TS 5.5.12 "Containment Leakage Rate Testing Program," and TS Surveillance Requirement (SR) 3.6.5.1.1, "Drywell," respectively, are required to be performed prior to start-up following GGNS Refueling Outage 22 (RF22), which commenced on February 22, 2020. This current requirement was previously approved by the NRC in Reference 23, and represents an extension of the Type A ILRT interval from 10 years to 11.5 years.

The proposed change would permit the ILRT and DWBT to be performed prior to start-up following RF23, which is scheduled to commence in February 2022. As such, the one-cycle extension of the ILRT and DWBT interval would represent a duration of approximately 13.5 years since the last performance of the ILRT and DWBT on October 19, 2008.

The proposed change to extend the ILRT and DWBT would enable Entergy to minimize the number of on-site personnel, thus minimizing the potential exposure of both essential (i.e., licensed operators, security personnel, and the emergency response organization) and non-essential personnel to the COVID-19 virus.

Entergy requests approval of the proposed amendment on an exigent basis, pursuant to 10 CFR 50.91(a)(6) to allow GGNS to resume operation following completion of the current GGNS refueling outage (i.e., RF22), which is scheduled to be completed in mid-April, 2020.

1.1 Differences from February 19, 2020 License Amendment Request

By letter dated February 19, 2020 (Reference 52), Entergy submitted a license amendment request (LAR) to allow a permanent extension of the Type A ILRT interval to once every 15 years. As part of the permanent extension LAR, Entergy performed a GGNS-specific evaluation to assess the risk impact of a 15-year permanent ILRT extension. This proposed one-cycle extension relies on the GGNS-specific risk evaluation, described in, and attached to the the non-risk-based performance and testing information, both of which were provided in the Reference 52 LAR. However, the content of the Reference 52 LAR has been modified, based on the difference in the requested extensions (i.e., a one-cycle 13.5-year extension versus a permanent 15-year extension). These differences are described below on a section by section basis.

<u>Section 1.0, "Summary Description"</u>
The *Summary Description* section has been revised to describe the one-cycle 13.5-year extension request, the reason for the request, and treatment of the request as exigent. In addition, this subsection (i.e., 1.1) has been added to describe the differences.

<u>Subsection 2.1, "Current Technical Specification Requirements"</u>
The *Current Technical Specification Requirments* subsection has been revised to delete numerous affected TS described in the Reference 52 LAR, such that only TS 5.5.12 and SR 3.6.5.1.1 are the affected TS.

Subsection 2.2, "Reason for the Proposed Change"
The *Reason for the Proposed Change* subsection has been completely changed to describe the need to minimize exposure of essential and non-essential personnel to the COVID-19 virus, and expeditiously return GGNS to service in support of the National Emergency Declaration due to the COVID-19 pandemic. In addition, this subsection describes current refueling outage testing and inspections associated with the Containment.

Subsection 2.3, "Description of the Proposed Change"
The *Description of the Proposed Change* subsection has been revised to delete all proposed TS changes, and replace with the relatively simple change to TS 5.5.12 and SR 3.6.5.1.1.

Subsection 2.4, "Basis for Exigency"
The *Basis for Exigency* subsection is a new subsection.

Subsection 3.4.1, (PRA) "Methodology"
The introduction to the *Methodology* subsection has been revised to state that the current one-cycle 13.5-year extension request utilizes the GGNS-specific risk assessment for the 15-year permanent extension that was described and provided in the Reference 52 LAR. In addition, clarification has been added to state that the description of the plant-specific risk assessment provided in Section 3.4, "Plant-Specific Risk Assessment" (i.e., Methodology, PRA Technical Adequacy, and Summary of Plant-Specific Risk Assessment Results) refers to a 15-year extension.

Section 3.9, "Conclusion"
The *Conclusion* section has been revised to apply the conclusion to a one-cycle 13.5-year ILRT extension, as opposed to a permanent 15-year extension.

Subsection 4.2, "Precedent"
The applicable precedents in the *Precedent* subsection have been revised to reflect the most recent one-cycle ILRT license amendments approved by the NRC, as opposed to approved permanent ILRT extensions.

Subsection 4.3, "No Significant Hazards Consideration"
The *No Significant Hazards Consideration* section has been revised to apply to a one-cycle 13.5-year ILRT extension, as opposed to a permanent 15-year extension.

Section 6.0, "References"
In the *References* section, Reference 52 was added as a new Reference, and Reference 22 was revised to specify a different precedent.

2.0 DETAILED DESCRIPTION

2.1 Current Technical Specification Requirements

GGNS TS 5.5.12, "10 CFR 50, Appendix J, Testing Program," currently states, in part:

> This program shall be implemented in accordance with the Safety Evaluation issued by the Office of Nuclear Reactor Regulation dated April 26, 1995 (GNRI-95/00087) as modified by the Safety Evaluation issued for Amendment No. 135 to the Operating

License, except that the next Type A test performed after the October 19, 2008 Type A test shall be performed no later than the plant restart after the End of Cycle 22 Refueling Outage.

The frequency for GGNS SR 3.6.5.1.1, "Drywell" states:

In accordance with the Surveillance Frequency Control Program except next drywell bypass leak rate test performed after the October 19, 2008 test shall be performed no later than the plant restart after the End of Cycle 22 Refueling Outage.

2.2 Reason for the Proposed Change

Current Refueling Outage Testing and Inspections

GGNS is currently conducting RF22. During this refueling outage, the following tests and inspections associated with containment have been, or will be completed prior to start-up.

- During RF-22, the entire IWE scope will be performed, with the exception of the Suppression Pool liner and bolted connections, both of which are only required to be inspected once per interval. Thus far in RF22, Entergy has completed all of the planned IWE scope, with the exception of a limited portion, due to limitations in removing Foreign Material Exclusion (FME) protective barriers preventing access to some areas on the containment liner. Inspection of these areas is being coordinated with FME barrier removal during containment closeout and will be completed prior to completion of the outage. All inspection results are still under review, but there have been no significant findings. Entergy did not perform any IWE or IWL inspections during RF21 (i.e., Spring 2018).

- Local leakage rate testing (LLRT) during RF22 is approximately 76% complete (i.e., 89 out of 119 air tests), with Type B and Type C test results indicating <34% of the $0.6L_a$ margin for Maximum Pathway Leakage and <16% of the $0.6L_a$ margin for Minimum Pathway Leakage. In addition, 19 of 22 water tests of Pressure Isolation Valves (PIVs) have been completed. All PIVs that have been water tested have passed the TS leakage criteria of ≤ 1 gpm. The integrated leakage of all water tests is at 11.4% of allowable leakage.

- During RF22, Entergy performed structural integrity walkdowns of the drywell interior wall and the inner and outer Containment walls to identify and document any signs of cracks, corrosion, peeling, chipped or flaked sections of concrete, or any damage to the walls or liner. The structural integrity walkdowns did not identify any new or significant issues.

GGNS is scheduled to perform a Type A ILRT prior to startup following RF22. Due to unforeseen factors arising from the COVID-19 pandemic, as described below, Entergy is requesting to extend the Type A ILRT and DWBT frequency to prior to startup following Refueling Outage 23 (RF23). This extension is necessary in order to protect personnel and ensure adequate sources of electrical generation are available during the current pandemic.

The COVID-19 pandemic has resulted in the following significant challenges to the station during RF22, all of which could threaten the timely return to service of GGNS.

- Loss of necessary resources, due to unavailability of vendors' operations
- Limited Personal Protective Equipment (PPE) for the COVID-19 virus
- The need to significantly limit onsite non-critical support staff
- The need to expeditiously release contracted outage support staff
- The need to reduce the risk of exposure to the station's critical staff (i.e., licensed operators, security personnel, and the emergency response organization)

The requested extension of the ILRT and DWBT frequencies from 11.5 years to 13.5 years (i.e., prior to startup following RF23) would support Entergy's ongoing efforts to minimize exposure of personnel to the COVID-19 virus by allowing for the timely and efficient release of contracted outage support staff and the transition of non-essential staff personnel to remote working arrangements as soon as possible.

2.3 Description of the Proposed Change

The proposed change to GGNS TS 5.5.12 and SR 3.6.5.1.1 will replace "End of Cycle 22" with "End of Cycle 23."

The proposed change revises the applicable text in GGNS TS 5.5.12 and SR 3.6.5.1.1to read as follows (with recommended changes using strike-out for deleted text and **bold-type** to show new text insertions, for clarification purposes):

TS 5.5.12

> This program shall be implemented in accordance with the Safety Evaluation issued by the Office of Nuclear Reactor Regulation dated April 26, 1995 (GNRI-95/00087) as modified by the Safety Evaluation issued for Amendment No. 135 to the Operating License, except that the next Type A test performed after the October 19, 2008 Type A test shall be performed no later than the plant restart after the End of Cycle ~~22~~ **23** Refueling Outage.

SR 3.6.5.1.1.

SURVEILLANCE		FREQUENCY
SR 3.6.5.1.1		In accordance with the Surveillance Frequency Control Program~~,~~ except that the next drywell bypass leak rate test performed after the October 19, 2008 test shall be performed no later than the plant restart after the End of Cycle ~~22~~ **23** Refueling Outage.

The mark-ups of the GGNS TS 5.5.12 and SR 3.6.5.1.1 are provided in Attachment 1. The retyped TS pages are provided in Attachment 2.

Attachment 3 provides a GGNS-specific risk assessment which was previously provided to the NRC in Reference 52 as part of a proposed license amendment to implement a permanent extension of the Type A ILRT interval to 15 years. This risk assessment follows the guidelines of NRC regulatory guide (RG) 1.174, Revision 3, (Reference 28) and RG 1.200, Revision 2, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," (Reference 45). The GGNS risk assessment concludes that increasing the ILRT test interval on a permanent basis to a 15 year interval is considered to represent a small change in the GGNS risk profile.

2.4 Basis for Exigency

The intent of the proposed change to extend the ILRT and DWBT frequencies from 11.5 years to 13.5 years is to minimize potential exposure of essential and non-essential personnel to the COVID-19 virus, and expeditiously return GGNS to service in support of the National Emergency declaration due to the COVID-19 pandemic.

GGNS is currently scheduled to perform a Type A ILRT and DWBT (i.e., SR 3.6.5.1.1), prior to entering Operational MODE 2 (startup). The MODE change is scheduled to occur in mid-April. Based on a mid-April MODE change, the requested approval date of the proposed change to extend the ILRT and DWBT interval is less than the 30-day federal register public notice period specified in 10 CFR 50.91(a)(6), therefore Entergy classifies this request as exigent in accordance with the cited regulation. Consistent with the requirements of 10 CFR 50.91(a)(6), Entergy believes that the need to minimize exposure of essential and non-essential personnel to the COVID-19 virus, and expeditiously return GGNS to service in support of the National Emergency Declaration could not have been avoided, and thus creates an exigent circumstance, based on the following:

- the unanticipated rapid COVID-19 infection rate and level of disability caused by the disease;
- the unprecedented rapid and fluid government response, including actual and potential quarantine orders;
- the need to protect critical staff by removal and relocation of unnecessary and non-essential individuals from the GGNS site;
- limited protective measures available at GGNS to prevent disease transmission; and
- the need to expeditiously return GGNS to service to support the national electrical grid critical infrastructure.

3.0 TECHNICAL EVALUATION

3.1 Description of Containment System

GGNS is designed with a General Electric Company boiling water reactor (BWR) enclosed by a Mark III type containment. The drywell is enclosed within the primary containment and is designed to divert the energy released during a design-basis, large-break loss of coolant accident (LOCA). The drywell communicates with the primary containment through a series of horizontal vents in the drywell wall.

These horizontal vents are covered both inside and outside the drywell by water from the annular shaped suppression pool. The pool forms a seal between the drywell and the primary containment. The drywell contains the reactor coolant system and other high energy piping systems.

3.1.1 Containment Building Description

The Containment structure is designed to house the primary nuclear system and is part of the containment system whose functional requirement is the control of the release of radioactivity from a primary nuclear system. The containment consists of three basic parts: a flat circular foundation mat, a right circular cylinder, and a hemispherical dome. The containment cylindrical wall, dome, and foundation mat are constructed of cast-in-place, conventionally reinforced concrete. For the most part, the Containment wall and foundation mat are separated by a 2-inch gap (which is filled with a compressible joint filler material) from the auxiliary building, to preclude significant interaction of these Category I structures during seismic disturbances.

3.1.2 Dimensions of Containment

- Inside diameter (ID): 124 ft. 0 in. (based on cylindrical wall inside radius of 62 ft.)
- Height of cylinder (top of foundation mat to dome spring line): 144 ft. 9 in.
- Inside radius of cylindrical wall: 62 ft. 0 in.
- Thickness of cylindrical walls: 3 ft. 6 in. (4 ft. 0 in. only in localized areas)
- Inside radius of dome: 62 ft. 0 in.
- Thickness of dome: 2 ft. 6 in.

- Foundation mat thickness: 9 ft. 6 in.
- Containment internal design pressure: 15 psig
- Containment airspace design temperature: 185 ^{o}F
- Suppression pool design temperature: 210 ^{o}F

3.1.3 Containment Penetrations and Attachments

Two personnel airlocks (Upper and Lower) and an equipment hatch provide access to the Containment structure. Containment airlocks are tested in accordance with 10 CFR 50, Appendix J, Option B.

Each containment airlock door has two inflatable seals that are maintained at a nominal pressure of 70 psig. Opening an airlock door, however, requires for its seals to be deflated. Before the other door on the same airlock can be opened, this door must be closed, and its seals must be re-inflated up to the 60 psig nominal interlock setpoint. This interlock ensures the pressure integrity of containment is maintained up to 56 psig when the airlocks are in use.

For the containment personnel locks, the airlock design incorporates provisions for testing between the door seals and between the doors. The provisions are (a.) testing of annulus between seals and (b.) overall airlock pressure test. Both tests can be run at a pressure of P_a.

Personnel air lock and equipment hatch openings penetrate the drywell cylindrical wall. Each of the two doors on the personnel air lock is fitted with two inflatable rubber seals to ensure the leak-tightness of the lock. The pressure within the seals can be monitored during normal operation to further ensure the integrity of the lock.

A horizontal fuel transfer tube penetration is provided at one end of the refueling pool to transfer fuel elements between the Containment and the Auxiliary Building.

Piping penetrating the containment has been equipped with test connections and test vents or has other provisions to allow periodic leak rate testing to ensure that leakage is within the acceptable limit as defined by the Technical Specifications and Appendix J of 10 CFR 50.

Typical mechanical and control systems penetrations are designed to be leak-tight. During normal operation, the leakage past these penetrations will be negligible.

3.2 Emergency Core Cooling System (ECCS) Net Positive Suction Head (NPSH) Analysis

NPSH available to the ECCS pumps has been determined in accordance with RG 1.1. Pressure drop across the ECCS/Reactor Core Isolation Cooling (RCIC) suction strainer is based on results from testing and conservative analysis. The vapor pressure for suppression pool water used in NPSH calculations for events where significant debris generation is expected is based on a suppression pool bulk water temperature of 210°F, which is the maximum design temperature of the containment. Analyses show maximum suppression pool temperatures to be less than the containment design temperature of 210°F. For events in which no significant debris generation is expected, NPSHA is evaluated for 212°F suppression pool water temperature. Containment pressure is assumed to be atmospheric in accordance with RG 1.1 requirements.

No credit is taken for the increase in containment pressure due to the accident (containment overpressurization).

3.3 Justification for the Technical Specification Change

3.3.1 Chronology of Testing Requirements of 10 CFR 50, Appendix J

The testing requirements of 10 CFR 50, Appendix J, provide assurance that leakage from the containment, including systems and components that penetrate the containment, does not exceed the allowable leakage values specified in the TS. 10 CFR 50, Appendix J, also ensures that periodic surveillance of reactor containment penetrations and isolation valves is performed so that proper maintenance and repairs are made during the service life of the containment and the systems and components penetrating primary containment. The limitation on containment leakage provides assurance that the containment would perform its design function following an accident up to and including the plant design basis accident. Appendix J identifies three types of required tests: (1) Type A tests, intended to measure the primary containment overall integrated leakage rate; (2) Type B tests, intended to detect local leaks and to measure leakage across pressure-containing or leakage limiting boundaries (other than valves) for primary containment penetrations; and, (3) Type C tests, intended to measure containment isolation valve (CIV) leakage rates. Types B and C tests identify the vast majority of potential containment leakage paths. Type A tests identify the overall (integrated) containment leakage rate and serve to ensure continued leakage integrity of the containment structure by evaluating those structural parts of the containment not covered by Types B and C testing.

In 1995, 10 CFR 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors," was amended to provide a performance-based Option B for the containment leakage testing requirements. Option B requires that test intervals for Type A, Type B, and Type C testing be determined by using a performance-based approach. Performance-based test intervals are based on consideration of the operating history of the component and resulting risk from its failure. The use of the term "performance-based" in 10 CFR 50, Appendix J refers to both the performance history necessary to extend test intervals as well as to the criteria necessary to meet the requirements of Option B.

Also, in 1995, RG 1.163 (Reference 1) was issued. The RG endorsed NEI 94-01, Revision 0 (Reference 4), with certain modifications and additions. Option B, in concert with RG 1.163 and NEI 94-01, Revision 0, allows licensees with a satisfactory ILRT performance history (i.e., two consecutive, successful Type A tests) to reduce the test frequency for the containment Type A

(ILRT) test from three tests in 10 years to one test in 10 years. This relaxation was based on an NRC risk assessment contained in NUREG-1493 (Reference 5) and Electric Power Research Institute (EPRI) TR-104285 (Reference 6), both of which showed that the risk increase associated with extending the ILRT surveillance interval was very small. In addition to the 10-year ILRT interval, provisions for extending the test interval an additional 15 months were considered in the establishment of the intervals allowed by RG 1.163 and NEI 94-01, but that this "…should be used only in cases where refueling schedules have been changed to accommodate other factors."

In 2008, NEI 94-01, Revision 2-A (Reference 3), was issued. This document describes an acceptable approach for implementing the optional performance-based requirements of Option B to 10 CFR 50, Appendix J, subject to the limitations and conditions noted in Section 4.0 of the NRC SE on NEI 94-01. The NRC SE was included in the front matter of this NEI report. NEI 94-01, Revision 2-A, includes provisions for extending Type A ILRT intervals to up to fifteen years and incorporates the regulatory positions stated in RG 1.163 (September 1995). It delineates a performance-based approach for determining Type A, Type B, and Type C containment leakage rate surveillance testing frequencies. Justification for extending test intervals is based on the performance history and risk insights.

NEI 94-01, Revision 2-A also states the following concerning Type A test surveillance intervals:

> Required surveillance intervals for recommended Type A testing given in this section may be extended by up to 9 months to accommodate unforeseen emergent conditions, but should not be used for routine scheduling and planning purposes.

In 2012, NEI 94-01, Revision 3-A (Reference 2), was issued. This document describes an acceptable approach for implementing the optional performance-based requirements of Option B to 10 CFR 50, Appendix J, and includes provisions for extending Type A ILRT intervals to up to fifteen years. NEI 94-01 has been endorsed by RG 1.163 (Reference 1) and NRC SEs of June 25, 2008 (Reference 7) and June 8, 2012 (Reference 8) as an acceptable methodology for complying with the provisions of Option B to 10 CFR Part 50. The regulatory positions stated in RG 1.163, as modified by the aforementioned NRC SEs (References 7 and 8), are incorporated in this document. It delineates a performance-based approach for determining Type A, Type B, and Type C containment leakage rate surveillance testing frequencies. Justification for extending test intervals is based on the performance history and risk insights. Extensions of Type B and Type C test intervals are allowed based upon completion of two consecutive periodic as-found tests where the results of each test are within a licensee's allowable administrative limits. Intervals may be increased from 30 months up to a maximum of 120 months for Type B tests (except for containment airlocks) and up to a maximum of 75 months for Type C tests. If a licensee considers extended test intervals of greater than 60 months for Type B or Type C tested components, the review should include the additional considerations of as-found tests, schedule and review as described in NEI 94-01, Revision 3-A, Section 11.3.2.

3.3.2 Current GGNS 10 CFR 50, Appendix J Requirements

10 CFR Part 50, Appendix J was revised, effective October 26, 1995, to allow licensees to choose containment leakage testing under either Option A, "Prescriptive Requirements," or Option B, "Performance Based Requirements." On April 6, 1998, the NRC approved License Amendment No. 135 for GGNS authorizing the implementation of 10 CFR Part 50, Appendix J, Option B for Types A, B and C tests (Reference 13).

Current TS 5.5.12 requires that a program be established to comply with the containment leakage rate testing requirements of 10 CFR 50.54(o) and 10 CFR Part 50, Appendix J, Option B, as modified by approved exemptions. The program is required to be conducted in accordance with the guidelines contained in an SE issued by the NRC on April 26, 1995, which approved, for GGNS, an exemption from the requirements of 10 CFR Part 50, Appendix J, Section III.D, as modified by the SE issued for Amendment No. 135 to the Operating License - except that the next Type A test performed after the October 19, 2008 Type A test was required to be performed no later than the plant restart after the End of Cycle 22 Refueling Outage.

For Type B and Type C local leakage rate testing, this program is required to be in accordance with the guidelines contained in NEI 94-01, Revision 3-A, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J," dated July 2012. GGNS TS 5.5.12 also states that, consistent with standard scheduling practices for TS-required surveillances, intervals for the recommended surveillance frequency for Type A testing may be extended by up to 25 percent of the test interval, not to exceed 15 months. The calculated peak containment internal pressure for the design basis loss of coolant accident, P_a, is 12.1 psig.

The differences between Amendment No. 135 and guidance provided in RG 1.163 are delineated in the NRC's SE for Amendment No. 135. RG 1.163 endorses, with certain exceptions, NEI 94-01, Revision 0, (Reference 4) as an acceptable method for complying with the provisions of 10 CFR 50, Appendix J, Option B.

3.3.3 GGNS 10 CFR 50, Appendix J, Option B Licensing History

April 26, 1995
The NRC granted an exemption to GGNS from the requirements of 10 CFR Part 50, Appendix J, Section III.D, to permit the selection of containment leakage rate testing intervals for components on the basis of performance (Reference 10). GGNS proposed changes to the frequency of performing Types A, B, and C tests including changes to the frequency of leakage rate testing of air locks. The exemption was to remain in effect until Refueling Outage 9.

Exemption from Section III.D.1(a):
Type A tests shall be performed on a 10-year interval provided that the two previous consecutive Type A tests, performed on the test interval specified in Appendix J (three tests, at approximately equal intervals, in a 10-year period), have been successful.

If a Type A test is failed, and the failure is not due to a Type B or C component, acceptable performance shall be re-established by performing a Type A test within 48-months of the unsuccessful Type A test. Following a successful Type A test, the surveillance frequency may be returned to once per 10 years.

In addition, the licensee must perform general inspections of the accessible interior and exterior surfaces of the containment structures, as specified in Section V.A of Appendix J, at the Type A test interval specified in Appendix J, even when no Type A test is required during that outage.

This exemption shall be valid from the beginning of Refueling Outage 7 to the first startup following Refueling Outage 9.

Exemption from Sections III.D.2 and III.D.3 of Appendix J:
Types B and C testing shall be performed according to the following algorithm. After two successful consecutive tests, performed at the Appendix J test interval of no more than two years, a Type B or C component may be tested once every 5 years. If this test or a subsequent test is a failure, the test interval for this component shall revert to a 2-year interval until the component passes two consecutive tests. The 5-year interval may then be resumed.

Main steam isolation valves, feedwater valves and containment system supply and exhaust isolation valves shall remain on a 2-year test interval. Any change will require prior review and approval by the NRC. The exemption shall be valid from the beginning of Refueling Outage 7 to the first startup following Refueling Outage 9.

Exemption from Section III.D.2(b)(i) and (b)(iii):
Air locks may be leakage rate tested at intervals of no more than 2 years. If an air lock fails a leakage rate test, the air lock shall then be required to pass two consecutive leakage rate tests at a test interval of 6 months prior to returning to the 2-year test interval. Following opening of an air lock door when containment integrity is required, the air lock shall be tested at least every 30 days. If an air lock fails a leakage rate test following opening of an air lock door when containment integrity is required, the air lock shall be required to pass two consecutive leakage rate tests at a test interval of 72 hours prior to returning to the 30-day interval. Since the GGNS air lock doors have testable seals, testing the seals fulfills the 30-day test requirement. This exemption shall be valid from the beginning of Refueling Outage 7 to the first startup following Refueling Outage 9.

August 1, 1996 – Amendment No. 126
The NRC issued License Amendment No. 126 for GGNS (Reference 11). The amendment revised and deleted surveillance requirements, notes, and action statements involved with the requirements for the drywell leak rate testing, and the air lock leakage and interlock testing in TS 3.6.5.1 (Drywell), 3.6.5.2 (Drywell air lock), and 3.6.5.3 (Drywell Isolation Valves).

October 18, 1996 – Amendment No. 128
The NRC approved License Amendment No. 128 for GGNS (Reference 12). The amendment revised the TS to modify the frequency requirements in surveillance requirement (SR) 3.6.1.3.5 on the leakage rate testing for each containment purge isolation valve with resilient seals to permit these valves to be leakage rate tested on a performance basis in accordance with 10 CFR 50, Appendix J.

April 6, 1998 – Amendment No. 135
The NRC approved License Amendment No. 135 for GGNS (Reference 13). The amendment revised the TS to permit the implementation of the containment leak rate testing provisions of 10 CFR Part 50, Appendix J, Option B. Specifically, this revision established a 10 CFR 50, Appendix J, Testing Program, and added this program to the TS. This program references the NRC's SE on the GGNS' exemption to Appendix J, dated April 26, 1995 (Reference 10), as a method acceptable to the NRC for complying with Option B. This included changes to existing TS SRs 3.6.1.1.1, 3.6.1.2.1, 3.6.1.3.5, 3.6.1.3.8, 3.6.1.3.9, and addition of the "10 CFR Part 50, Appendix J, Testing Program" as TS 5.5.12. The applicable TS Bases were also modified.

As stated in the NRC's SE for Amendment No. 135 (Reference 13), the NRC's April 26, 1995, SE (Reference 10) limited the test intervals for Types B and C testing to 5 years. GGNS had opted to extend the Type B test interval to 10 years and keep the Type C interval at its present value of 5 years. This was consistent with RG 1.163.

In addition, according to Reference 13, GGNS also opted to use alternative testing or analysis in lieu of as-found tests when maintenance is performed. RG 1.163 does not endorse use of alternative testing or analysis in lieu of as-found testing. However, GGNS stated it was current practice to use valve operation test and evaluation system (VOTES) testing in lieu of a local leakage rate test (LLRT) for maintenance that does not affect leak-tightness, which GGNS defined as maintenance that affects only the valve actuator. GGNS stated that an LLRT would only be performed if VOTES test detected a degraded thrust value, which could indicate seat leakage. This position is consistent with 10 CFR 50, Appendix J, Option B and was acceptable to the NRC.

In addition, GGNS also proposed that following opening of an air lock door when containment integrity is required, the air locks shall be tested at least every 30 days. This 30-day test requirement may be satisfied by testing the air lock door seals. The NRC found this acceptable, since the differences between the GGNS proposal and the testing mandated by NEI 94-01 are not significant.

The NRC determined that the use of the guidance in the April 26, 1995 SE is consistent with the intent of RG 1.163 (Reference 1) and was therefore acceptable.

March 14, 2001 – Amendment No. 145

The NRC approved License Amendment No. 145 for GGNS (Reference 14). The amendment consisted of changes to the facility FOL and TS for a full-scope implementation of the alternative source term (AST).

Among these changes was a revision to TS SR 3.6.1.3.8, Main Steam Isolation Valve (MSIV) Leakage Rate, to increase the maximum allowable leak rate to less than or equal to 100 standard cubic feet per hour (scfh) per main steam line (MSL) with a total leak rate through all four MSLs of less than or equal to 250 scfh (from less than or equal to 100 scfh through all four MSLs).
This amendment also revised TS 1.1, "Definitions," to reference new dose conversion factors and to increase the maximum allowable primary containment leakage rate from 0.437 percent to 0.682 percent of primary containment air weight per day (wt%/day). This value is based on 0.35 percent per day from the containment leak and an additional 100 scfh (0.087 percent per day) through the steam lines.

January 28, 2004 – Amendment No. 164

The NRC approved License Amendment No. 164 regarding the one-cycle extension of the ILRT and drywell bypass test interval for GGNS (Reference 15). The amendment changed the administrative TS 5.5.12 regarding containment ILRT and TS 3.6.5.1.1 regarding drywell bypass leak rate testing (DWBT). The change would allow for a one-cycle extension of the interval from 10 to 15 years for performance of the next ILRT and DWBT. This change added an exception to the commitment to implement the containment ILRT program in accordance with the SE issued by the Office of Nuclear Reactor Regulation dated April 26, 1995 (GNRI-95/00087), as modified by the SE issued for Amendment No. 135 to the Operating License.

Specifically, GGNS revised TS 5.5.12 by adding to the end of the second sentence the following:

> ", except that the next Type A test performed after the November 24, 1993 Type A test shall be performed no later than November 23, 2008."

In addition, GGNS also revised TS 3.6.5.1.1 by adding an exception to the Frequency requirement of 120 months that states:

> ", except that the next drywell bypass leak rate test performed after the November 24, 1993 test shall be performed no later than November 23, 2008."

These changes represented a one-cycle deferral of the ILRT and the DWBT by up to five additional years.

July 12, 2005 – Amendment No. 168
The NRC approved License Amendment No. 168 for GGNS (Reference 16). The amendment revised the air lock surveillance test acceptance criteria to be consistent with the NRC approved industry TS Task Force (TSTF) change to the Standard TS, TSTF-52, entitled, "Implement 10 CFR Part 50, Appendix J, Option B." In summary, GGNS adopted the containment air lock leakage rate specified as a percentage of the maximum allowable primary containment leakage L_a, in the ISTS rather than the absolute leakage rate previously specified in the GGNS TS.

August 24, 2007 – Amendment No. 176
The NRC approved License Amendment No. 176 for GGNS (Reference 17). This amendment revised the GGNS TS to allow certain types of relief valves to be used to isolate a containment penetration flow path without being deactivated under specific criteria. The NRC has allowed similar types of penetrations and valves to be excluded from the scope of Appendix J containment leakage testing through issuance of 10 CFR 50.69, "Risk-Informed Categorization and Treatment of Structures, Systems, and Components for Nuclear Power Reactors." The basis for these approvals was that containment leakage through these types of penetrations and valves were determined to not contribute in a significant way to diminishing safety or increasing risk.

July 18, 2012 – Amendment No. 191
The NRC approved License Amendment No. 191 for GGNS (Reference 18). This amendment increased the maximum steady-state reactor core power level by approximately 15% from the original licensed thermal power level of 3,833 MWt [i.e., extended power uprate (EPU)].

The license was amended to including a new license condition 2.C.(44) for the SRs related to leak rate tests associated with TS 5.5.12 [10 CFR 50, Appendix J, Testing Program] are not required to be performed until their next scheduled performance dates. These tests will be performed at the EPU calculated peak containment pressure or within EPU drywell bypass leakage limits, as appropriate.

This amendment also changed TS 5.5.12 calculated peak containment internal pressure for the design basis loss of coolant accident, Pa, from 11.5 psig to 14.8 psig.

December 26, 2013 – Amendment No. 197
The NRC approved License Amendment No. 197 for GGNS (Reference 19). The amendment revised the TS for GGNS to support operation with 24-month fuel cycles. Specifically, the amendment revised the frequency of certain TS SRs from 18 months to 24 months in accordance with Generic Letter 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991 (Reference 49).

August 31, 2015 – Amendment No. 205
The NRC approved License Amendment No. 205 for GGNS (Reference 27). The amendment revised the GGNS TS to allow plant operation from the currently licensed Maximum Extended Load Line Limit Analysis (MELLLA) domain to plant operation in the expanded MELLLA Plus (MELLLA+) domain under the previously approved EPU condition of 4408 megawatts thermal rated core thermal power.

This amendment also changed TS 5.5.12 calculated peak containment internal pressure for the design basis LOCA, P_a, from 14.8 to 12.1 psig.

February 17, 2016 – Amendment No. 209
The NRC approved License Amendment No. 209 for GGNS (Reference 20). The amendment revised the GGNS TS to allow for a permanent extension of the Type C leakage rate testing frequency and reduction of the Types B and C grace intervals that are required by GGNS TS 5.5.12, "10 CFR 50, Appendix J, Testing Program," by including a reference to NEI Topical Report, NEI 94-01, Revision 3-A, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J," dated July 2012. In addition, the amendment changed TS 5.5.12 and SR 3.6.5.1.1 by deleting the information regarding the performance of the last ILRT/DWBT that had already occurred.

December 29, 2017 – Amendment No. 214
The NRC approved License Amendment No. 214 for GGNS (Reference 23). The amendment allowed a one-cycle extension to the 10-year frequency of the GGNS containment leakage rate test (i.e., ILRT and the DWBT). These tests are required by GGNS TS 5.5.12, "10 CFR 50 Appendix J, Testing Program," and TS SR 3.6.5.1.1, respectively. The change permits existing ILRT and DWBT frequencies to be extended from 10 years to 11.5 years between tests. This extension allowed the performance of the next ILRT and DWBT from the scheduled spring 2018 End of Cycle (EOC) 21 refueling outage to the spring 2020 EOC 22 refueling outage.

June 11, 2019 – Amendment No. 219
The NRC approved License Amendment No. 219 for GGNS (Reference 24). The amendment revised the TS by relocating specific surveillance frequencies to a licensee-controlled program consistent with the NRC-approved TSTF Improved STS Change Traveler TSTF-425, Revision 3, "Relocate Surveillance Frequencies to Licensee Control - RITSTF [Risk-informed TSTF] Initiative 5b."

The Probabilistic Risk Assessment Licensing Branch A (APLA) reviewed the SE input for GGNS, LAR to implement TSTF-425, Revision 3, proposed changes using the generic requirements identified in TSTF-425. The APLA staff found that the methodology and approach used by GGNS were consistent with TSTF-425 and therefore acceptable (Reference 25).

3.3.4 Integrated Leakage Rate Testing (ILRT) History

Previous Type A tests confirmed that the GGNS reactor containment structure has leakage well under acceptance limits and represents minimal risk to increased leakage. Continued Type B and Type C testing for direct communication with containment atmosphere minimizes this risk. Also, the Inservice Inspection (ISI) (IWE/IWL) program and Maintenance Rule monitoring provide confidence in containment integrity.

To date, five operational Type A tests have been performed on GGNS. There is considerable margin between these Type A test results and the TS 5.5.12 limit of 0.75 L_a (0.5115% weight per day), where L_a is equal to 0.682% weight per day of the containment air mass at the peak accident pressure. These test results demonstrate that GGNS has a low leakage Containment.

Table 3.3.4-1, Integrated Leakage Rate Testing (ILRT) History		
Test Date	**95% UCL**	**As-Left Leakage weight % per day**
January 5, 1982	0.083	0.083
November 4, 1985	0.141	0.145
April 16, 1989	0.129	0.133
November 21, 1993	-0.155 [1]	0.210
October 19, 2008	0.2076	0.248

Note 1. Refer to Table 3.3.5-1 below for reconciliation of negative result.

3.3.5 Integrated Leakage Rate Testing, Performance Leakage Rate Determination

The current ILRT test interval for GGNS is ten years. Verification of this interval is presented in Table 3.3.5-1. The acceptance criteria used for this verification is contained in NEI 94-01, Revisions 2-A and 3-A, Section 5.0, Definitions, and is as follows:

The **performance leakage rate** is calculated as the sum of the Type A upper confidence limit (UCL) and as-left minimum pathway leakage rate (MNPLR) leakage rate for all Type B and Type C pathways that were in service, isolated, or not lined up in their test position (i.e., drained and vented to containment atmosphere) prior to performing the Type A test. In addition, leakage pathways that were isolated during performance of the test because of excessive leakage must be factored into the performance determination. The performance criterion for Type A tests is a performance leak rate of less than 1.0 La.

Table 3.3.5-1: Verification of Current Extended ILRT Interval for GGNS						
Test Date	**95% UCL Leakage Rate (wt.%/day) (Test Pressure)**	**Pressure and Volume Level Corrections (wt.%/day)**	**Types B and C Penalties (wt.%/day)**	**Components Isolated During ILRT (wt.%/day**	**Performance Leakage Rate (wt.%/day)**	**Acceptance Criteria (wt.%/day)**
11/21/1993	-0.155 (11.915 psig, P_a = 11.5 psig)	0.311	0.052	0.002	0.210	0.328
10/19/2008	0.2076 (12.45 psig, P_a = 11.5 psig)	0.0331	0.0071	0	0.2478	0.5115 (1)

Note 1. The limit for the 2008 test was 0.5115 wt%/day. This was changed as part of the implementation of the alternate source term (Reference 14).

3.4 Plant Specific Risk Assessment

3.4.1 Methodology

By letter dated February 19, 2020 (Reference 52), Entergy submitted a proposed GGNS license amendment requesting approval for a permanent extension of the Type A ILRT frequency to 15 years. As part of that proposed license amendment, Entergy performed a plant-specific risk assessment of permanently extending the current Type A ILRT frequency to 15 years.

In that this proposed license amendment requests a one-cycle change to 13.5 years, the risk assessment that was performed for the permanent 15-year extension is directly applicable to, and bounds the proposed one-cycle extension. As such, the description of the plant-specific risk assessment provided below (i.e., Methodology, PRA Technical Adequacy, and Summary of Plant-Specific Risk Assessment Results) refers to a 15-year extension. The plant-specific risk assessment is provided in Attachment 3.

The risk assessment follows the guidelines from:

- NEI 94-01, Revision 3-A (Reference 2),
- The methodology used in EPRI TR-104285 (Reference 6),
- The NEI "Interim Guidance for Performing Risk Impact Assessments in Support of One-Time Extensions for Containment Integrated Leakage Rate Test Surveillance Intervals," from November 2001 (Reference 26),
- The NRC regulatory guidance on the use of Probabilistic Risk Assessment (PRA) as stated in RG 1.200 as applied to ILRT interval extensions, risk insights in support of a request for a plant’s licensing basis as outlined in RG 1.174 (Reference 28),
- The methodology used for Calvert Cliffs to estimate the likelihood and risk implications of corrosion-induced leakage of steel liners going undetected during the extended test interval (Reference 29),
- The methodology used in EPRI 1018243, Revision 2-A of EPRI 1009325 (Reference 30).

Revisions to 10 CFR 50, Appendix J (Option B) allow individual plants to extend the ILRT Type A surveillance testing frequency requirement from three in ten years to at least once in ten years. The revised Type A frequency is based on an acceptable performance history defined as two consecutive periodic Type A tests at least 24 months apart in which the calculated performance leakage rate was less than limiting containment leakage rate of $1.0L_a$.

The basis for the current 10-year test interval is provided in Section 11.0 of NEI 94-01, Revision 0, and was established in 1995 during development of the performance-based Option B to Appendix J. Section 11.0 of NEI 94-01 states that NUREG-1493, "Performance-Based Containment Leak Test Program," September 1995 (Reference 5), provides the technical basis to support rulemaking to revise leakage rate testing requirements contained in Option B to Appendix J. The basis consisted of qualitative and quantitative assessment of the risk impact (in terms of increased public dose) associated with a range of extended leakage rate test intervals. To supplement the NRC's rulemaking basis, NEI undertook a similar study. The results of that study are documented in EPRI Research Project TR-104285, "Risk Impact Assessment of Revised Containment Leak Rate Testing Intervals."

The NRC report on performance-based leak testing, NUREG-1493, analyzed the effects of containment leakage on the health and safety of the public and the benefits realized from the containment leak rate testing. In that analysis, it was determined that for a representative BWR plant (i.e., Peach Bottom), that increasing the containment leak rate from the nominal 0.5% per day to 5% per day leads to a barely perceptible increase in total population exposure, and increasing the leak rate to 50% per day increases the total population exposure by less than 1%. Because ILRTs represent substantial resource expenditures, it is desirable to show that extending the ILRT interval will not lead to a substantial increase in risk from containment isolation failures to support a reduction in the test frequency for GGNS.

NEI 94-01, Revision 3-A supports using EPRI Report No. 1009325 Revision 2-A (EPRI 1018243), "Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals," for performing risk impact assessments in support of ILRT extensions (Reference 9). The guidance provided in Appendix H of EPRI 1018243 builds on the EPRI Risk Assessment methodology, EPRI TR-104285. This methodology is followed to determine the appropriate risk information for use in evaluating the impact of the proposed ILRT changes.

It should be noted that containment leak-tight integrity is also verified through periodic in-service inspections conducted in accordance with the requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI. More specifically, Subsection IWE provides the rules and requirements for inservice inspection (ISI) of Class MC pressure-retaining components and their integral attachments, and of metallic shell and penetration liners of Class CC pressure-retaining components and their integral attachments in light-water cooled plants. Furthermore, NRC regulations in 10 CFR 50.55a(b)(2)(ix)(E) require licensees to conduct visual inspections of the accessible areas of the interior of the containment. The associated change to NEI 94-01 will require that visual examinations be conducted during at least three other outages, and in the outage during which the ILRT is being conducted. These requirements will not be changed as a result of the extended ILRT interval. In addition, Appendix J, Type B local leak tests performed to verify the leak-tight integrity of containment penetration bellows, airlocks, seals, and gaskets are also not affected by the change to the Type A test frequency.

The acceptance guidelines in RG 1.174 are used to assess the acceptability of this permanent extension of the Type A test interval beyond that established during the Option B rulemaking of Appendix J. RG 1.174 defines very small changes in the risk-acceptance guidelines as increases in Core Damage Frequency (CDF) less than 10-6 per reactor year and increases in Large Early Release Frequency (LERF) less than 10-7 per reactor year. Since containment accident pressure is not required in support of ECCS performance to mitigate design basis accidents at GGNS (Reference Section 3.2 of this submittal), the ILRT extension does not impact CDF. Therefore, the more relevant risk-impact metric is LERF. RG 1.174 also defines small changes in LERF as below 10-6 per reactor year. RG 1.174 discusses defense-in-depth and encourages the use of risk analysis techniques to help ensure and show that key principles, such as the defense-in-depth philosophy, are met. Therefore, the increase in the Conditional Containment Failure Probability (CCFP), which helps ensure the defense-in-depth philosophy is maintained, is also calculated.

Table 3.4.1-1 provides the limitations/conditions delineated in EPRI Report No. 1009325, Revision 2 and the GGNS responses to each of these limitations/conditions.

Table 3.4.1-1: EPRI Report No. 1009325, Revision 2 - Limitations and Conditions

Limitation/Condition (from Section 4.2 of SE)	GGNS Response
1. The licensee submits documentation indicating that the technical adequacy of their PRA is consistent with the requirements of RG 1.200 relevant to the ILRT extension.	GGNS PRA technical adequacy is addressed in Section 3.4.2 of this LAR and Attachment 4, "Evaluation of Risk Significance of Permanent ILRT Extension," Appendix A, PRA Model Technical Adequacy.
2.a. The licensee submits documentation indicating that the estimated risk increase associated with permanently extending the ILRT surveillance interval to 15 years is small, and consistent with the clarification provided in Section 3.2.4.5 of this SE.	Since the ILRT does not impact CDF, the relevant criterion is LERF. The increase in internal events LERF resulting from a change in the Type A ILRT test interval from 3 in 10 years to 1 in 15 years is estimated as 1.66E-8/year using the EPRI guidance; this value increases negligibly if the risk impact of corrosion-induced leakage of the steel liners occurring and going undetected during the extended test interval is included. As such, the estimated change in LERF is determined to be "very small" using the acceptance guidelines of RG 1.174 (Reference 28). When external event risk is included, the increase in LERF resulting from a change in the Type A ILRT test interval from 3 in 10 years to 1 in 15 years is estimated as 3.12E-7/year using the EPRI guidance, and total LERF is 4.66E-6/year. As such, the estimated change in LERF is determined to be "small" using the acceptance guidelines of RG 1.174. The risk change resulting from a change in the Type A ILRT test interval from 3 in 10 years to 1 in 15 years bounds the 1 in 10 years to 1 in 15 years risk change. When external event risk is included, the increase in LERF resulting from a change in the Type A ILRT test interval from 1 in 10 years to 1 in 15 years is estimated as 1.30E-7 and the total LERF is 4.48E-6. Therefore, the risk increase is "small"

Table 3.4.1-1: EPRI Report No. 1009325, Revision 2 - Limitations and Conditions	
Limitation/Condition (from Section 4.2 of SE)	**GGNS Response**
	using the acceptance guidelines of RG 1.174. (See Attachment 4, Section 7 of this submittal.)
2.b. Specifically, a small increase in population dose should be defined as an increase in population dose of less than or equal to either 1.0 person-rem per year or 1% of the total population dose, whichever is less restrictive.	The effect resulting from changing the Type A test frequency to 1-per-15 years, measured as an increase to the total integrated plant risk for those accident sequences influenced by Type A testing, is 0.006 person-rem/year. NEI 94-01 (Reference 3) states that a "small" population dose is defined as an increase of ≤ 1.0 person-rem per year, or ≤ 1% of the total population dose, whichever is less restrictive for the risk impact assessment of the extended ILRT intervals. The results of this calculation meet these criteria. Moreover, the risk impact for the ILRT extension when compared to other severe accident risks is negligible. (See Attachment 4, Section 7 of this submittal.)
2.c. In addition, a small increase in CCFP should be defined as a value marginally greater than that accepted in a previous one-time 15-year ILRT extension requests. This would require that the increase in CCFP be less than or equal to 1.5 percentage point.	The increase in the conditional containment failure probability from the 3 in 10-year interval to 1 in 15-year interval is 0.642%. NEI 94-01 [Reference 3] states that increases in CCFP of ≤ 1.5% are "small." Therefore, this increase is judged to be small. (See Attachment 4, Section 7 of this submittal.)
3. The methodology in EPRI Report No. 1009325, Revision 2, is acceptable except for the calculation of the increase in expected population dose (per year of reactor operation). In order to make the methodology acceptable, the average leak rate accident case (accident case 3b) used by the licensees shall be 100 L_a instead of 35 L_a.	The representative containment leakage for Class 3b sequences is 100L_a based on the guidance provided in EPRI Report No. 1009325, Revision 2-A (EPRI 1018243) (Reference 9). (See Attachment 4, Section 4 of this submittal.)
4. A license amendment request (LAR) is required in instances where containment over-pressure is relied upon for ECCS performance.	Containment overpressure is not required for ECCS performance and is discussed in Section 3.2 of this submittal. Therefore, no additional request is required.

3.4.2 PRA Technical Adequacy

3.4.2.1 Internal Events PRA Quality Statement for Permanent 15-Year ILRT Extension

The current GGNS PRA model of record is Revision 4b which contains multiple significant enhancements and is used for this analysis (Reference 32). This model and its technical content

were constructed and documented to meet the ASME/ANS PRA standard (Reference 33). The PRA model quantification methodology used at Entergy nuclear sites is common and well known to the industry.

Entergy's approach for maintaining, updating, and documenting the PRA models at all Entergy nuclear sites is controlled in the fleet procedures. These procedures are consistent with the guidance of the ASME/ANS PRA standard. The procedural process is comprehensive and detailed, which in turn provides the basis for establishing and maintaining the technical adequacy of the models, as well as ensuring the models reflect the as-built, as-operated plant configuration of the sites. Entergy procedures define the process to be followed to implement scheduled and interim PRA model updates and to control the PRA model files. Periodic PRA model updates are typically performed at least once every four years, with the option of extending the frequency for up to an additional two years, such that the total update period does not exceed six years. Extensions are justified by showing that the PRA model continues to adequately represent the as-built, as-operated plant and must be approved by management. Thus, using these models for this Type A test analysis meets the technical adequacy requirements.

3.4.2.2 Peer Review Facts and Observations (F&Os)

The GGNS PRA model has undergone several peer reviews, which document the model quality and identify any areas with potential for improvement. The following assessments have been performed and documented for the GGNS model.

- The Boiling Water Reactor Owners Group (BWROG) conducted a peer review certification (Reference 34) of the GGNS PRA model Revision 1 in October 1997 (Reference 35). The peer review concluded that the GGNS PRA was sufficient to support meaningful rankings for the assessment of SSCs and judged capable of supporting absolute risk determination to support applications.

- A full-scope industry peer review of the GGNS PRA model Revision 4 (Reference 36) was conducted by the BWROG September 21-25, 2015 (Reference 37). This peer review documented sixty-six (66) new F&Os including thirty-nine (39) Findings, twenty-six (26) Suggestions, and one (1) Best Practice. The peer review concluded that the GGNS PRA substantially (approximately 85% of the Supporting Requirements) met the ASME/ANS PRA standard at Capability Category II or better. This model revision was not issued for use because the PRA model was updated to Revision 4a to resolve the F&Os.

The GGNS PRA internal events model Revision 4a was approved in October 2017 (Reference 32) and incorporated changes, as applicable, to support the resolutions of the 2015 peer review findings. The 2015 peer review findings and the associated resolutions are documented in the model change request (MCR) database and a resolution summary report (Reference 38). The full-scope peer review findings from 2015 were closed by an independent assessment conducted August 23-31, 2017. The closure assessment was conducted in accordance with Appendix X to NEI 05-04 (Reference 39) utilizing the conditions of acceptance stated in an NRC letter to NEI dated May 3, 2017 (Reference 40).

The independent assessment is documented in the closure report (Reference 41) and concluded that none of the changes made to the GGNS PRA were considered a PRA upgrade or use of a new PRA method. All finding-level F&Os from the 2015 full-scope industry PRA peer review have been closed by an independent assessment conducted August 23-31, 2017, and are listed in

Attachment 4, Table A-2. The table includes the resolutions and conclusions of the F&Os. In addition, the listing documents the basis for each F&O to validate whether the F&O constituted a PRA upgrade, maintenance update, or other; and documents the results from the independent assessment team review of the supporting requirements to ensure that Capability Category II of the ASME PRA standard was met for the F&Os.

3.4.2.3 Consistency with Applicable PRA Standards

The GGNS PRA model Revision 4b meets the ASME/ANS PRA standard (Reference 33) Capability Category II of the Supporting Requirements. Current Entergy PRA documentation includes a self-assessment that documents how each high-level requirement (HLR) and Supporting Requirement is met.

The latest full-scope peer review for GGNS was conducted in September 2015 (Reference 37) using the ASME/ANS PRA standard. Since then, model Revisions 4a and 4b have been completed to address the peer review findings, incorporate some elements of FLEX, and perform additional enhancements (Reference 32). All the F&Os are captured and documented in the MCR database and the resolution summary report (Reference 38). No finding level F&Os remain open for the GGNS internal events and internal flooding PRA.

3.4.2.4 Seismic PRA

The Seismic PRA results from the Individual Plant Examination of External Events (IPEEE) Seismic Margins Analysis do not result in an estimate of CDF (Reference 42). The seismic CDF values reported in Table D-1 of GI-199 (Reference 43) are used for estimating Seismic CDF in this calculation.

3.4.2.5 Fire PRA Model

GGNS does not currently have a fire PRA model. The results of the fire risk assessment performed for the IPEEE are used for this analysis, and the risk results are considered reasonable.

3.4.2.6 Conclusion

This information demonstrates the PRA is of sufficient quality and level of detail to support the ILRT extension analysis.

3.4.3 Summary of Plant-Specific Risk Assessment Results

Based on the results from Attachment 4, Section 5.2 and the sensitivity calculations presented in Section 5.3, the following conclusions regarding the assessment of the plant risk are associated with extending the Type A ILRT test frequency to 15 years:

- RG 1.174 (Reference 28) provides guidance for determining the risk impact of plant-specific changes to the licensing basis. RG 1.174 defines very small changes in risk as resulting in increases of CDF less than 1.0E-06/year and increases in LERF less than 1.0E-07/year. Since the ILRT does not impact CDF, the relevant criterion is LERF. The increase in internal events LERF resulting from a change in the Type A ILRT test interval from 3-in-10 years to 1-in-15 years is estimated as 1.66E-8/year using the EPRI guidance;

this value increases negligibly if the risk impact of corrosion-induced leakage of the steel liners occurring and going undetected during the extended test interval is included. As such, the estimated change in LERF is determined to be "very small" using the acceptance guidelines of RG 1.174.

- When external event risk is included, the increase in LERF resulting from a change in the Type A ILRT test interval from 3-in-10 years to 1-in-15 years is estimated as 3.12E-7/year using the EPRI guidance, and total LERF is 4.66E-6/year. As such, the estimated change in LERF is determined to be "small" using the acceptance guidelines of RG 1.174. The risk change resulting from a change in the Type A ILRT test interval from 3-in-10 years to 1-in-15 years bounds the 1-in-10 years to 1-in-15 years risk change. When external event risk is included, the increase in LERF resulting from a change in the Type A ILRT test interval from 1-in-10 years to 1-in-15 years is estimated as 1.30E-7 and the total LERF is 4.48E-6. Therefore, the risk increase is "small" using the acceptance guidelines of RG 1.174.

- The effect resulting from changing the Type A test frequency to 1-per-15 years, measured as an increase to the total integrated plant risk for those accident sequences influenced by Type A testing, is 0.006 person-rem/year. NEI 94-01 states that a "small" population dose is defined as an increase of ≤ 1.0 person-rem per year, or ≤ 1% of the total population dose, whichever is less restrictive for the risk impact assessment of the extended ILRT intervals. The results of this calculation meet these criteria. Moreover, the risk impact for the ILRT extension when compared to other severe accident risks is negligible.

- The increase in the conditional containment failure probability from the 3 in 10-year interval to 1 in 15-year interval is 0.642%. NEI 94-01 (Reference 2) states that increases in CCFP of ≤ 1.5% are "small." Therefore, this increase is judged to be small.

Therefore, increasing the ILRT interval to 15 years is considered to be insignificant since it represents a small change to the GGNS risk profile.

3.4.4 Previous Assessments

The NRC in NUREG-1493 (Reference 5) has previously concluded that:

- Reducing the frequency of Type A tests (ILRTs) from 3-per-10 years to 1-per-20 years was found to lead to an imperceptible increase in risk. The estimated increase in risk is very small because ILRTs identify only a few potential containment leakage paths that cannot be identified by Type B or Type C testing, and the leaks that have been found by Type A tests have been only marginally above existing requirements.

- Given the insensitivity of risk to containment leakage rate and the small fraction of leakage paths detected solely by Type A testing, increasing the interval between integrated leakage rate tests is possible with minimal impact on public risk. The impact of relaxing the ILRT frequency beyond 1 in 20 years has not been evaluated. Beyond testing the performance of containment penetrations, ILRTs also test integrity of the containment structure.

The findings for GGNS confirm these general findings on a plant-specific basis considering the severe accidents evaluated for GGNS, the GGNS containment failure modes, and the local population surrounding GGNS.

3.4.5 RG 1.174, Revision 3, Defense-in-Depth Evaluation

RG 1.174, Revision 3 (Reference 28) describes an approach that is acceptable for developing risk-informed applications for a licensing basis change that considers engineering issues and applies risk insights. One of the considerations included in RG 1.174, Revision 3 is Defense-in-Depth. Defense-in-Depth is a safety philosophy that employs successive compensatory measures to prevent accidents or mitigate damage if a malfunction, accident, or naturally caused event occurs at a nuclear facility. The following seven considerations as presented in RG 1.174, Revision 3, Section C.2.1.1.2 will serve to evaluate the proposed licensing basis change for overall impact on Defense-in-Depth.

TS Amendment No. 209 dated February 17, 2016 (Reference 20) revised TS 5.5.12, "10 CFR 50, Appendix J, Testing Program," to adopt the guidance in NEI 94-01, Revision 3-A, for Types B and C testing. This change allowed GGNS to extend the Type C test interval from 60 months up to 75 months, based on acceptable performance. The impact of the previous extension of the Type C test interval, in accordance with NEI 94-01, Revision 3-A will be incorporated in the following Defense-in-Depth evaluation, as it is germane to this evaluation.

1. Preserve a reasonable balance among the layers of defense.

A reasonable balance of the layers of defense (i.e., minimizing challenges to the plant, preventing any events from progressing to core damage, containing the radioactive source term, and emergency preparedness) helps to ensure an apportionment of the plant's capabilities between limiting disturbances to the plant and mitigating their consequences. The term "reasonable balance" is not meant to imply an equal apportionment of capabilities. The NRC recognizes that aspects of a plant's design or operation might cause one or more of the layers of defense to be adversely affected. For these situations, the balance between the other layers of defense becomes especially important when evaluating the impact of the proposed licensing basis change and its effect on defense in depth.

Response:
Several layers of defense are in place to ensure the GGNS containment structure(s), penetrations, isolation valves, and mechanical seal systems continue(s) to perform their intended safety function. The purpose of the proposed change is to extend the testing frequencies of the Type A ILRT from 10 years to 15 years in addition to the previous extension of Type C LLRTs for selected components from 60-months to 75-months.

As shown in NUREG-1493, Performance-Based Containment Leak-Test Program (Reference 5), increasing the test frequency of ILRTs up to a 20-year test interval was found to lead to an imperceptible increase in risk. The estimated increase in risk is very small because ILRTs identify only a few potential containment leakage paths that cannot be identified by Type B or Type C testing. The study also concluded that extending the frequency of Type B tests is possible with no adverse impact on risk as identified leakage through Type B mechanical penetrations are both infrequent and small. Finally, the study

concluded that Types B and C tests could identify the vast majority (greater than 95 percent) of all potential leakage paths.

Several programmatic factors can also be cited as layers of defense ensuring the continued safety function of the GGNS containment pressure boundary. NEI 94-01, Revisions 2-A and 3-A, require sites adopting the 15-year extended ILRT interval perform visual examinations of the accessible interior and exterior surfaces of the containment structure for structural degradation that may affect the containment leak-tight integrity at the frequency prescribed by the guidance or, if approved through a TS amendment, at the frequencies prescribed by ASME Section XI. Additionally, several measures are put in place to ensure integrity of the Types B and C tested components. NEI 94-01 limits large containment penetrations such as airlocks, purge and vent valves, boiling water reactor (BWR) main steam and feedwater isolation valves, to a maximum 30-month testing interval. For those valves that meet the performance standards defined in NEI 94-01, Revision 3-A, and are selected for test intervals greater than 60 months, a leakage understatement "penalty" is added to the MNPLR prior to the frequency being extended beyond 60-months. Finally, identification of adverse trends in the overall Types B and C leakage rate summations and available margin between the Type B and Type C leakage rate summation and its regulatory limit are required by NEI 94-01, Revision 3-A, to be shown in the GGNS post-outage report(s). Therefore, the proposed change does not challenge or limit the layers of defense available to assess the ability of the GGNS containment structure to perform its safety function.

PRA Response:
The use of the risk metrics of LERF, population dose, and conditional containment failure probability collectively ensures the balance between prevention of core damage, prevention of containment failure, and consequence mitigation is preserved. The change in LERF is "small" per RG 1.174, and the change in population dose and CCFP are "small" as defined in this analysis [provided in Attachment 4 of this submittal] and are consistent with NEI 94-01, Revision 3-A.

2. Preserve adequate capability of design features without an overreliance on programmatic activities as compensatory measures.

Nuclear power plant licensees implement a number of programmatic activities, including programs for quality assurance, testing and inspection, maintenance, control of transient combustible material, foreign material exclusion, containment cleanliness, and training. In some cases, activities that are part of these programs are used as compensatory measures; that is, they are measures taken to compensate for some reduced functionality, availability, reliability, redundancy, or other feature of the plant's design to ensure safety functions (e.g., reactor vessel inspections that provide assurance that reactor vessel failure is unlikely). NUREG-2122, "Glossary of Risk-Related Terms in Support of Risk-Informed Decision Making," (Reference 50) defines "safety function" as those functions needed to shut down the reactor, remove the residual heat, and contain any radioactive material release.

A proposed licensing basis change might involve or require compensatory measures. Examples include hardware (e.g., skid-mounted temporary power supplies); human actions (e.g., manual system actuation); or some combination of these measures. Such compensatory measures are often associated with temporary plant configurations. The

preferred approach for accomplishing safety functions is through engineered systems. Therefore, when the proposed licensing basis change necessitates reliance on programmatic activities as compensatory measures, the licensee should justify that this reliance is not excessive (i.e., not overly reliant). The intent of this consideration is not to preclude the use of such programs as compensatory measures but to ensure that the use of such measures does not significantly reduce the capability of the design features (e.g., hardware).

Response:
The purpose of the proposed change is to extend the testing frequencies of the Type A ILRT from 10 years to 15 years in addition to the previous extension of select Type C LLRTs from 60-months to 75-months. Several programmatic factors were defined in the response to Question 1 above, which are required when adopting NEI 94-01, Revisions 2-A and 3-A. These factors are conservative in nature and are designed to generate corrective actions if the required testing or inspections are deemed unsatisfactory well in advance to ensure the continued safety function of the containment is maintained. The programmatic factors are designed to provide differing ways to test and/or examine the containment pressure boundary in a manner that verifies the GGNS containment pressure boundary will perform its intended safety function. Since the proposed change does not alter the configuration of the GGNS containment pressure boundary, continued performance of the tests and inspections associated with NEI 94-01 will only serve to ensure the continued safety function of the containment without affecting any margin of safety.

PRA Response:
The adequacy of the design feature (the containment boundary subject to Type A testing) is preserved as evidenced by the overall "small" change in risk associated with the Type A test frequency change.

3. Preserve system redundancy, independence, and diversity commensurate with the expected frequency and consequences of challenges to the system, including consideration of uncertainty.

As stated in RG 1.174, Section C.2.1.1.1, the defense-in-depth philosophy has traditionally been applied in plant design and operation to provide multiple means to accomplish safety functions.

System redundancy, independence, and diversity result in high availability and reliability of the function help ensure that system functions are not reliant on any single feature of the design. Redundancy provides for duplicate equipment that enables the failure or unavailability of at least one set of equipment to be tolerated without loss of function. Independence of equipment implies that the redundant equipment is separate such that it does not rely on the same supports to function.

This independence can sometimes be achieved by the use of physical separation or physical protection. Diversity is accomplished by having equipment that performs the same function rely on different attributes such as different principles of operation, different physical variables, different conditions of operation, or production by different manufacturers, which helps reduce common-cause failure (CCF).

A proposed change might reduce the redundancy, independence, or diversity of systems. The intent of this consideration is to ensure that the ability to provide the system function is commensurate with the risk of scenarios that could be mitigated by that function. The consideration of uncertainty, including the uncertainty inherent in the PRA, implies that the use of redundancy, independence, or diversity provides high reliability and availability, and results in the ability to tolerate failures or unanticipated events.

Response:
The proposed change to extend the testing frequencies of the Type A ILRT from 10 years to 15 years in addition to the previous extension of select Type C LLRTs from 60-months to 75-months does not reduce the redundancy, independence, or diversity of systems. As shown in NUREG-1493, increasing the test frequency of ILRTs up to a 20-year test interval was found to lead to an imperceptible increase in risk. The estimated increase in risk is very small because ILRTs identify only a few potential containment leakage paths that cannot be identified by Type B or Type C testing. The study also concluded that extending the frequency of Type B tests is possible with no adverse impact on risk as identified leakage through Type B mechanical penetrations are both infrequent and small. Additionally, the study concluded that Types B and C tests could identify the vast majority (greater than 95 percent) of all potential leakage paths.

Despite the change in test interval, containment isolation diversity remains unaffected and will continue to provide the inherent isolation, as designed. In addition, NEI 94-01, Revisions 2-A and 3-A, Section 11.3.2 requires a schedule of tests be developed, for components on a test interval greater than 60 months, such that unanticipated random failures and unexpected common-mode failures are avoided. This is typically accomplished by implementing test intervals at approximately evenly distributed intervals. Therefore, the proposed change preserves system redundancy, independence, and diversity and ensures a high reliability and availability of the containment structure to perform its safety function in the event of unanticipated events.

PRA Response:
The redundancy, independence, and diversity of the containment subject to the Type A test is preserved, commensurate with the expected frequency and consequences of challenges to the system, as evidenced by the overall "small" change in risk associated with the Type A test frequency change.

4. Preserve adequate defense against potential common-cause failures (CCFs).

An important aspect of ensuring defense-in-depth is to guard against CCF. Multiple components may fail to function because of a single specific cause or event that could simultaneously affect several components important to risk. The cause or event may include an installation or construction deficiency, accidental human action, extreme external environment, or an unintended cascading effect from any other operation or failure within the plant. CCFs can also result from poor design, manufacturing, or maintenance practices. Defenses can prevent the occurrence of failures from the causes and events that could allow simultaneous multiple component failures. Another aspect of guarding against CCF is to ensure that an existing defense put in place to minimize the impact of CCF is not significantly reduced; however, a reduction in one defense can be compensated for by adding another.

Response:
As part of the proposed change, GGNS will be required to adopt the performance-based testing standards outlined in NEI 94-01, Revisions 2-A and 3-A, along with ANSI/ANS 56.8-2002 (Reference 30). NEI 94-01, Revisions 2-A and 3-A, Section 11.3.2 requires a schedule of tests be developed, for components on test intervals greater than 60 months, such that unanticipated random failures and unexpected common-mode failures are avoided. This is typically accomplished by implementing test intervals at approximately evenly distributed intervals. In addition, components considered to be risk-significant from a PRA standpoint are required to be limited to a testing interval less than the maximum allowable limit of 75-months. For those components that have demonstrated satisfactory performance and have had their testing limits extended, administrative testing limits are assigned on a component-by-component basis and are used to identify potential valve or penetration degradation. Administrative limits are established at a value low enough to identify and should allow early correction in advance of total valve failure. Should a component exceed its administrative limit during testing, NEI 94-01, Revisions 2-A and 3-A, require cause determinations be performed designed to reinforce achieving acceptable performance. The cause determination is designed to identify and address common-mode failure mechanisms through appropriate corrective actions. The proposed change also imposes a requirement to address "margin management" (i.e., margin between the current containment leakage rate and its pre-established limit). As a result, adoption of the performance-based testing standards proposed by this change ensures adequate barriers exist to preclude failure of the containment pressure boundary due to common-mode failures and, therefore, continues to guard against CCF.

PRA Response:
Adequate defense against CCFs is preserved. The Type A test detects problems in the containment, which may or may not be the result of a CCF; such a CCF may affect failure of another portion of containment (i.e., local penetrations) due to the same phenomena. Adequate defense against CCFs is preserved via the continued performance of the Types B and C tests and the performance of inspections. The change to the Type A test, which bounds the risk associated with containment failure modes including those involving CCFs, does not degrade adequate defense as evidenced by the overall "small" change in risk associated with the Type A test frequency change.

5. Maintain multiple fission product barriers.

Fission product barriers include the physical barriers themselves (e.g., the fuel cladding, reactor coolant system pressure boundary, and containment) and any equipment relied on to protect the barriers (e.g., containment spray). In general, these barriers are designed to perform independently so that a complete failure of one barrier does not disable the next subsequent barrier. For example, one barrier, the containment, is designed to withstand a double-ended guillotine break of the largest pipe in the reactor coolant system, another barrier.

A plant's licensing basis might contain events that, by their very nature, challenge multiple barriers simultaneously. Examples include interfacing-system loss-of-coolant accidents, steam generator tube rupture, or crediting containment accident pressure. Therefore, complete independence of barriers, while a goal, might not be achievable for all possible scenarios.

Response:
The purpose of the proposed change is to extend the testing frequencies of the Type A ILRT from 10 years to 15 years in addition to the previous extension of select Type C LLRTs from 60-months to 75-months. As part of the proposed change, GGNS will be required to adopt the performance-based testing standards outlined in NEI 94-01, Revisions 2-A and 3-A, along with ANSI/ANS 56.8-2002. The overall containment leakage rate calculations associated with the testing standards contain inherent conservatisms through the use of margin. Plant TS require the overall primary containment leakage rate to be less than or equal to 1.0 L_a. NEI 94-01 requires that the As-Found Type A test leakage rate must be less than the acceptance criterion of 1.0 L_a given in the plant TS. Prior to entering a mode where containment integrity is required, the As-Left Type A leakage rate shall not exceed 0.75 L_a. The As-Found and As-Left values are as determined by the appropriate testing methodology specifically described in ANSI/ANS-56.8-2002. Additionally, the combined leakage rate for all Type B and Type C tested penetrations shall be less than or equal to 0.6 L_a, determined on a maximum pathway basis from the As-Left LLRT results prior to entering a mode where containment integrity is required. This regulatory approach results in a 25% and 40% margin, respectively, to the 1.0 L_a requirements. For those local leak rate tested components that have demonstrated satisfactory performance and have had their testing limits extended, administrative testing limits are assigned on a component-by-component basis and are used to identify potential valve or penetration degradation. Administrative limits are established at a value low enough to identify and allow early correction in advance of total valve failure. Should a component exceed its administrative limit during testing, NEI 94-01, Revisions 2-A and 3-A, require causal determinations be performed designed to reinforce achieving acceptable performance. The cause determination is designed to identify and address common-mode failure mechanisms through appropriate corrective actions. Therefore, the proposed change adopts requirements with inherent conservatisms to ensure the margin to safety limit is maintained; thereby, preserving the containment fission product barrier.

PRA Response:
Multiple Fission Product barriers are maintained. The portion of the containment affected by the Type A test extension is still maintained as an independent fission product barrier, albeit with an overall "small" change in the reliability of the barrier.

6. Preserve sufficient defense against human errors.

Human errors include the failure of operators to correctly and promptly perform the actions necessary to operate the plant or respond to off-normal conditions and accidents, errors committed during test and maintenance, and incorrect actions by other plant staff. Human errors can result in the degradation or failure of a system to perform its function, thereby significantly reducing the effectiveness of one of the layers of defense or one of the fission product barriers. The plant design and operation include defenses to prevent the occurrence of such errors and events. These defenses generally involve the use of procedures, training, and human engineering; however, other considerations (e.g., communication protocols) might also be important.

Response:
Sufficient defense against human errors is preserved. Errors committed during testing and maintenance may be reduced by the less frequent performance of the Type A, Type B, and Type C tests (less opportunity for errors to occur).

PRA Response:
Sufficient defense against human errors is preserved. The probability of a human error to operate the plant, or to respond to off-normal conditions and accidents is not significantly affected by the change to the Type A testing frequency. Errors committed during test and maintenance may be reduced by the less frequent performance of the Type A test (less opportunity for errors to occur).

7. Continue to meet the intent of the plant's design criteria.

For plants licensed under 10 CFR Part 50 or 10 CFR Part 52, the plant's design criteria are set forth in the current licensing basis (CLB) of the plant. The plant's design criteria define minimum requirements that achieve aspects of the defense-in-depth philosophy; As a consequence, even a compromise of the intent of those design criteria can directly result in a significant reduction in the effectiveness of one or more of the layers of defense. When evaluating the effect of the proposed licensing basis change, the licensee should demonstrate that it continues to meet the intent of the plant's design criteria.

Response:
The purpose of the proposed change is to extend the testing frequencies of the Type A ILRT from 10 years to 15 years in addition to the previous extension of select Type C LLRTs from 60-months to 75-months. The proposed extensions do not involve either a physical change to the plant or a change in the manner in which the plant is operated or controlled. As part of the proposed change, GGNS will be required to adopt the performance-based testing standards outlined in NEI 94-01, Revisions 2-A and 3-A, along with ANSI/ANS 56.8-2002. The leakage limits imposed by plant TS remain unchanged when adopting the performance-based testing standards outlined in NEI 94-01, Revision 3-A, and ANSI/ANS 56.8-2002. Plant design limits imposed by the Updated Final Safety Analysis Report (UFSAR) also remain unchanged as a result of the proposed change. Therefore, the proposed change continues to meet the intent of the plant's design criteria to ensure the integrity of the GGNS containment pressure boundary.

PRA Response:
The intent of the plant's design criteria continues to be met. The extension of the Type A test does not change the configuration of the plant or the way the plant is operated.

<u>Conclusion</u>:
The responses to the seven Defense-in-Depth questions above conclude that the existing Defense-in-Depth has not been diminished; rather, in some instances has been increased. Therefore, the proposed change does not comprise a reduction in safety.

3.5 Non-Risk Based Assessment

3.5.1. Containment Leakage Rate Testing Program - Types B and C Testing Program

GGNS Types B and C testing program requires testing of electrical penetrations, airlocks, hatches, flanges, and containment isolation valves in accordance with the SE issued by the NRC dated April 26, 1995, as modified by the SE issued for Amendment No. 135 to the Operating License. For Types B and C LLRTs, this program shall be in accordance with the guidelines contained in NEI 94-01, Revision 3-A, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J," dated July 2012. The results of the test program are used to demonstrate that proper maintenance and repairs are made on these components throughout their service life. The Types B and C testing program provides a means to protect the health and safety of plant personnel and the public by maintaining leakage from these components below appropriate limits. Per TS 5.5.12 and SR 3.6.1.1.1 program requirements, the allowable maximum pathway total Types B and C leakage is 0.6 L_a where 0.6 L_a equals approximately 198,000 sccm (L_a equal approximately 330,000 sccm).

As discussed in NUREG-1493 (Reference 5), Types B and C tests can identify the vast majority of all potential containment leakage paths. Types B and C testing will continue to provide a high degree of assurance that containment integrity is maintained.

A review of the Types B and C test results from 2005 through 2016 for GGNS has shown an exceptional amount of margin between the actual As-Found (AF) and As-left (AL) outage summations and the regulatory requirements as described below:

- The As-Found minimum pathway leak rate for GGNS shows an average of 13.22% of 0.6 L_a with a high of 19.32% of 0.6 L_a or 0.1159 L_a.

- The As-Left maximum pathway leak rate for GGNS shows an average of 40.63% of 0.6 L_a with a high of 61.68% of 0.6 L_a or 0.3701 L_a.

Table 3.5.1-1 provides the LLRT data trend summaries for GGNS since 2008 and encompasses previous ILRTs. This summary shows that there has been <u>no</u> As-Found failure that resulted in exceeding the TS 5.5.12 and SR 3.6.1.1.1 limit of 0.6 L_a (198,000 sccm) and demonstrates a history of successful tests. The As-Found minimum pathway summations represent the high quality of maintenance of Types B and C tested components while the As-Left maximum pathway summations represent the effective management of the Containment Leakage Rate Testing Program by the program owner.

Table 3.5.1-1, Types B and C LLRT Combined As-Found/As-Left Trend Summary

RFO	2008 RF16	2010 RF17	2012 RF18	2014 RF19	2016 RF20	2018 RF21
AF Min Path (sccm)	18,984	18,057	24,453	21,595	35,760	38,250
Fraction of L_a (%)	5.75	5.47	7.41	6.54	10.84	11.59
AL Max Path (sccm)	57,793	69,850	93,069	79,014	122,136	60,799

Table 3.5.1-1, Types B and C LLRT Combined As-Found/As-Left Trend Summary						
RFO	**2008 RF16**	**2010 RF17**	**2012 RF18**	**2014 RF19**	**2016 RF20**	**2018 RF21**
Fraction of L_a (%)	17.51	21.17	28.2	23.94	37.01	18.42
AL Min Path (sccm)	23,457	25,065	30,415	35,054	35,474[1]	32,384[1]
Fraction of L_a (%)	7.11	7.60	9.22	10.62	10.75	9.81

[1] Leakage understatement is incorporated into the As-Left MinPath during RF20 and RF21 as a result of incorporation of NEI 94-01, Rev. 3-A (Reference 20).

Table 3.5.1-2 identifies the components on extended intervals that have not demonstrated acceptable performance during the previous two outages for GGNS:

Table 3.5.1-2: Types B and C LLRT Program Implementation Review						
Component [Penetration No.]	**As-Found SCCM**	**Admin Limit SCCM**	**As-Left SCCM**	**Cause of Failure**	**Corrective Action**	**Scheduled Interval**
2016 RF20						
1B33F125 [81]	20,000 (MinPath = 0)	260	2	Seat leakage	Adjusted valve operator torque setting to reduce leakage.	Interval set at 24 months
2018 RF21						
P53F002 [42]	800	650	450	Seat leakage	Valve replaced	Interval set at 24 months
E12F044A [20]	1275	1040	1280	Seat leakage	Accepted as is	Interval set at 24 months

<u>Type B and Type C Tested Components on Extended Intervals</u>

The percentage of the total number of GGNS Type B tested components (78) that are on extended performance-based test intervals is 65%.

The percentage of the total number of GGNS Type C tested components (151) that are on extended performance-based test interval is 56%.

3.5.2 Supplemental Inspections

In the SER for NEI 94-01, Revision 2-A (Reference 3), the NRC stated the following requirement for the performance of Supplemental Visual Inspections in the SE Section 3.1.1.3, Adequacy of Pre-Test Inspections (Visual Examinations):

> Subsections IWE and IWL of the ASME Code, Section XI, as incorporated by reference in 10 CFR 50.55a, require general visual examinations two times within a 10-year interval for concrete components (Subsection IWL), and three times within a 10-year interval for steel

components (Subsection IWE). To avoid duplication or deletion of examinations, licensees using NEI TR 94-01, Revision 2, must develop a schedule for containment inspections that satisfy the provisions of Section 9.2.3.2 of this TR and ASME Code, Section XI, Subsection IWE and IWL requirements.

GGNS SR 3.6.5.1.2 requires the visual inspection of the exposed accessible interior and exterior surfaces of the drywell at a frequency of once prior to performance of each Type A test required by SR 3.6.1.1.1. The performance of inspections in accordance with the requirements for Appendix J, Primary Containment Inspection, will be utilized to ensure compliance with the visual inspection requirements of NEI 94-01, Revision 3-A.

The exposed accessible drywell interior and exterior surfaces are inspected to ensure there are no apparent physical defects that would prevent the drywell from performing its intended function. This SR ensures that drywell structural integrity is maintained. The frequency was chosen so that the interior and exterior surfaces of the drywell can be inspected in conjunction with the inspections of the primary containment required by 10 CFR 50, Appendix J and ASME Section XI, Subsections IWE and IWL. Due to the passive nature of the drywell structure, the specified Frequency is sufficient to identify component degradation that may affect drywell structural integrity.

3.5.3 Service Level 1 (SL1) Coatings Assessment

Purpose

The purpose of the Service Level 1 Coatings Assessment program is to monitor the condition of SL1 coatings and provide an effective method to assess coating condition through visual inspections to identify degraded or damaged coatings and provide a means for repair of identified problem area.

Significance and Use

A coating monitoring program provides early identification and detection of potential problems in coating systems. Degraded coatings have the potential to fail if they are not upgraded/repaired by a maintenance program. Failure of coating material and rust may generate debris under design basis accident conditions that could adversely affect the performance of post-accident safety systems, such as ECCS suction strainers.

Establishment of an ongoing inservice monitoring program allows for planning and scheduling of priority coating activities to ensure the integrity and performance of SL1 coating systems.

Frequency of Inspections

Inspections of coatings in the drywell are to be performed during Refueling Outages. Containment inspection may be performed during operation.

- For non-immersion coatings, a general walk down should be performed every refuel outage or other major maintenance outages. Plant-specific commitments (e.g., plant TS, trending results, IWE/IWL inspections, etc.) may affect the frequency of assessment.

- For containments with immersion coatings, coating monitoring inspections should be performed every three to five years, unless plant specific commitments require more frequent inspections.

Records and Past History of Existing Coatings
The last two performance monitoring reports pertaining to the SL1 coating systems should be reviewed prior to the monitoring process.

Inspection Plan
Perform a walk-through visual inspection on all readily accessible coated surfaces if historical information is not available. After the walkthrough, detailed visual inspection shall be performed on previously designated areas and on areas documented as possible deficiencies by the initial walk-through inspection.
Where defects exist on the containment boundary, the following rules apply:

- Notify the containment Responsible Professional Engineer (Design Engineering Programs) of location and extent of degradation potentially affecting the containment boundary such as blisters, cracks, corrosion, which affects the base metal.

- VT-3 Visual Exam must be performed before removing coatings or surface preparation as per ASME Section XI. Following repair or reapplication of coating, a copy of the Coatings Inspection Report shall be attached to the VT-3 Report.

Identification of visible defects such as blistering, cracking, flaking/peeling, rusting, and physical damage.

- Blistering – compare any blistering found to the blistering pictorial standards of coating defects (refer to test method D714) and record size and frequency, if blisters are larger than those on the comparison photographs, measure, record size and extent of surface area affected. Photograph area and report if the blisters are intact.

- Cracking – can be limited to one layer of coating or extend through to the substrate. Measure the length of the crack or if extensive cracking has occurred, measure the size of the area affected. Determine if cracking is isolated or is part of a pattern. Record depth of crack length, and pattern of crack on the inspection report, photograph the area affected.

- Flaking Peeling Delamination – Measure the size of peels and note pattern formed. Carefully check to see if lifting can be achieved beyond the obvious peeled area. Note all observations on the inspection report and photograph the area affected.

- Rusting – compare with the pictorial standards ASTM of test method D610 to determine the degree of rusting. Try to determine the source of rusting, is it surface stain caused by rust in another location or is it a failure of the coating allowing the substrate to rust. Photograph the affected area and record observations.

- If no defects are found – mark "coatings intact, no defects" on the inspection reports.

- If portions of the coating cannot be inspected – note the specific areas on the location map-inspection report, along with the reason why the inspection cannot be conducted.

Written or photographic documentation, or both of coating inspection area, failures, and defects shall be made and the processing of documentation will be determined by the inspection coordinator. Practice ASTM D4121 provides one method to obtain consistent comparable close-up photographs.

For coating surfaces determined to be suspect, defective or deficient, one or more physical tests, such as dry film thickness (test methods ASTM D1186 and SSPC-PA-2), adhesion ASTM (Test Methods D3359 and D4541), and continuity (NACE RP0188-88) may be performed and evaluated by the coating specialist. Samples may be gathered, and the size and extent of defective patterns may be described.

Evaluation

The inspection reports should be evaluated by responsible qualified evaluation personnel. The evaluation personnel shall prepare a report that includes a summary of findings and recommendations for future surveillance or repair; this would include an analysis of the reasons or suspected reasons for failure. The repair work should be prioritized into large and small defective areas. A recommended corrective plan or action must be provided for the large (area larger than 1 sq. ft.), defective areas so that the plant can repair these areas, if required during the same outage.

Condition Reports must be written on Nonconforming Items. A coating failure such as loss of adhesion, delamination, blistering, flaking, etc., is considered nonconforming. Damaged coating areas are considered a maintenance item and will be addressed by a Work Request.

3.5.4 Containment Inservice Inspection Program

Introduction

This Program Section contains the details of the ASME Section XI, Division 1, Containment Inservice Inspection (CISI) Program for GGNS. Implementation of a Containment Inservice Inspection Program in accordance with the requirements of ASME Section XI, Division 1, is mandated by 10 CFR 50.55a.

This Program Section contains the details of the ASME Section XI, Division 1, Containment Inservice Inspection (CISI) Program for GGNS. Implementation of a Containment Inservice Inspection Program is in accordance with the requirements of ASME Section XI, Division 1, as mandated by 10 CFR 50.55a.

The scope of this Program Section includes the examination and testing of ASME Section XI Class CC and Class MC Components and their integral attachments for the Fourth Ten-Year Inservice Inspection Interval.

ASME Section XI Code of Record for the Fourth Ten-Year CISI Interval

10 CFR 50.55a(g)(5)(i) for the ISI program update, which is also applicable to the CISI Program, states that the program must be revised to meet the requirements of 10 CFR 50.55a(g)(4), (g)(4)(i) and (g)(4)(ii). This requires that ISI of components and system pressure tests conducted during successive 120-month inspection intervals must comply with the requirements of the latest edition and addenda of the ASME Section XI Code incorporated by reference 12 months prior to the start of the 120-month inspection interval.

The initial Containment ISI Program commenced on June 2, 1997 and continued through June 1, 2007. The interval was extended until May 31, 2008, as permitted under IWA- 2430(d).

The Code of Record for the initial second interval was the 1992 Edition with the 1992 Addenda of ASME Section XI, as modified by 10 CFR 50.55a. Those portions of the program affected by Relief Request CEP-IWE/IWL-001 were developed in accordance with the 1998 Edition with 2000 Addenda of ASME Section XI.

The Code of Federal Regulations Final Rule that affected the CISI Program Update for GGNS was the 10 CFR 50.55a Final Rule published September 29, 2005 (70FR188). 70FR188 incorporated by reference ASME Section XI, 2001 Edition, 2003 Addenda in paragraph (b)(2) and was effective November 1, 2004.

The Code of Record for the Third Ten-Year Interval was ASME Boiler and Pressure Vessel Code Section XI, 2001 Edition 2003 Addenda. The Third Ten-Year Interval dates were from May 31, 2008, concluding on November 30, 2017, thus reclaiming 6 months of the 12-month extension that occurred in the 2nd interval.

In accordance with 10 CFR 50.55a(g), Entergy is required to update the ASME Section XI Containment ISI Program once every ten years. The updated Containment ISI Program is required to comply with the latest edition and addenda of the Code incorporated by reference in 10 CFR 50.55a(a)(1)(ii) one year prior to the start of the interval per 10 CFR 50.55a(g)(4)(ii).

Because the fourth interval began on December 1, 2017, the 10 CFR 50.55a in effect one year prior (December 1, 2016), requires the Containment ISI Program meet the requirements of ASME Section XI, 2007 Edition through the 2008 Addenda.

The CISI Program Section for ASME Section XI Class CC and Class MC components for the Fourth Ten-Year CISI Interval is developed using the ASME Boiler and Pressure Vessel Code, Section XI, 2007 Edition through the 2008 Addenda; except where specific written alternatives from Code requirements have been requested by Entergy and granted by the NRC or as amended by the NRC in 10 CFR 50.55a.

<u>IWE (Class MC) Inspection Interval and Periods</u>
This Fourth Ten-Year Interval Program for the performance of Containment ISI complies with IWE-2411 and commenced on December 1, 2017 and will end on November 30, 2027. These dates were determined from the regulatory requirements of 10 CFR 50.55a. The three periods, within the interval, are defined in ASME Section XI and are as follows:

- First Period December 1, 2017, through November 30, 2020 (3 years)
- Second Period December 1, 2020, through November 30, 2024 (4 years)
- Third Period December 1, 2024, through November 30, 2027 (3 years)

The Fifth Ten-Year Interval Program for the performance of Containment ISI complies with IWE-2411 and will commence on December 1, 2027 and will end on November 30, 2037. These dates are proposed as the Fifth Ten-Year Interval Program has yet to be developed. The three periods, within the interval, are defined in ASME Section XI and are as follows:

- First Period December 1, 2027, through November 30, 2030 (3 years)
- Second Period December 1, 2030, through November 30, 2034 (4 years)
- Third Period December 1, 2034, through November 30, 2037 (3 years)

Per IWA-2430(c)(1), each inspection interval may be reduced or extended by as much as one year. Adjustments shall not cause successive intervals to be altered by more than one year from the original pattern of intervals. If an inspection interval is extended, neither the start and end dates nor the ISI program for the successive interval needs to be revised.

Note: Within the ASME Section XI, Code of Record, Table IWE-2411-1, Inspection Program, allows and requires percentages and limits of examinations to be performed each inspection period, but based on the Examination Requirements of Table IWE-2500-1, Examination Categories E-A, E-C, and E-G, where all required examinations within these Examination Categories are to be completed either 100% each Inspection Period or 100% each Inspection Interval. No partial percentages are applicable and, thus, the Table is not used in this CISI Program.

IWL (Class CC) Inspection Periods
This program plan for the Fourth Ten-Year CISI Interval is effective December 1, 2017, through November 30, 2027, for IWL inspections conducted in accordance with the 5-year period schedule contained in Table 3.5.4-1 and Figure 3.5.4-1.

Concrete examinations shall be conducted every five years (+/-1 year) as described in IWL-2410(a) and (c). For the purposes of the CISI Program, an IWL inspection period is five years, with two periods per inspection interval. An IWL inspection period shall commence not more than 1 year prior to the specified dates and shall be completed not more than 1 year after such dates. If plant operating conditions are such that examination of portions of the concrete cannot be completed within this stated time interval, examination of those portions may be deferred until the next regularly scheduled plant outage.

The requirements of IWL-2410(b) did not apply to GGNS during the initial Containment ISI Second Interval because more than 5 years had passed since the Structural Integrity Test (SIT) was completed on January 2, 1982. The five-year inspection periods depicted in Table 3.5.4-1 are based on the SIT date of January 2, 1982.

Concrete surface areas, as described in IWL-2410(d), affected by a repair/replacement activity shall be examined in accordance with the requirements of IWL-2510 at 1 year (+3 months) following completion of repair/replacement activity. If plant operating conditions are such that examination of portions of the concrete cannot be completed within this time interval, examination of those portions may be deferred until the next regularly scheduled plant outage.

Table 3.5.4-1, GGNS Projected IWL Examination Periods

Period	Date	Tolerance
40-Year	1/2/2022	+/- 1 Year
45-Year	1/2/2027	+/- 1 Year
50-Year	1/2/2032	+/- 1 Year
55-Year	1/2/2037	+/- 1 Year
60-Year	1/2/2042	+/- 1 Year

Figure 3.5.4-1, GGNS 4th Interval IWE and IWL Schedule

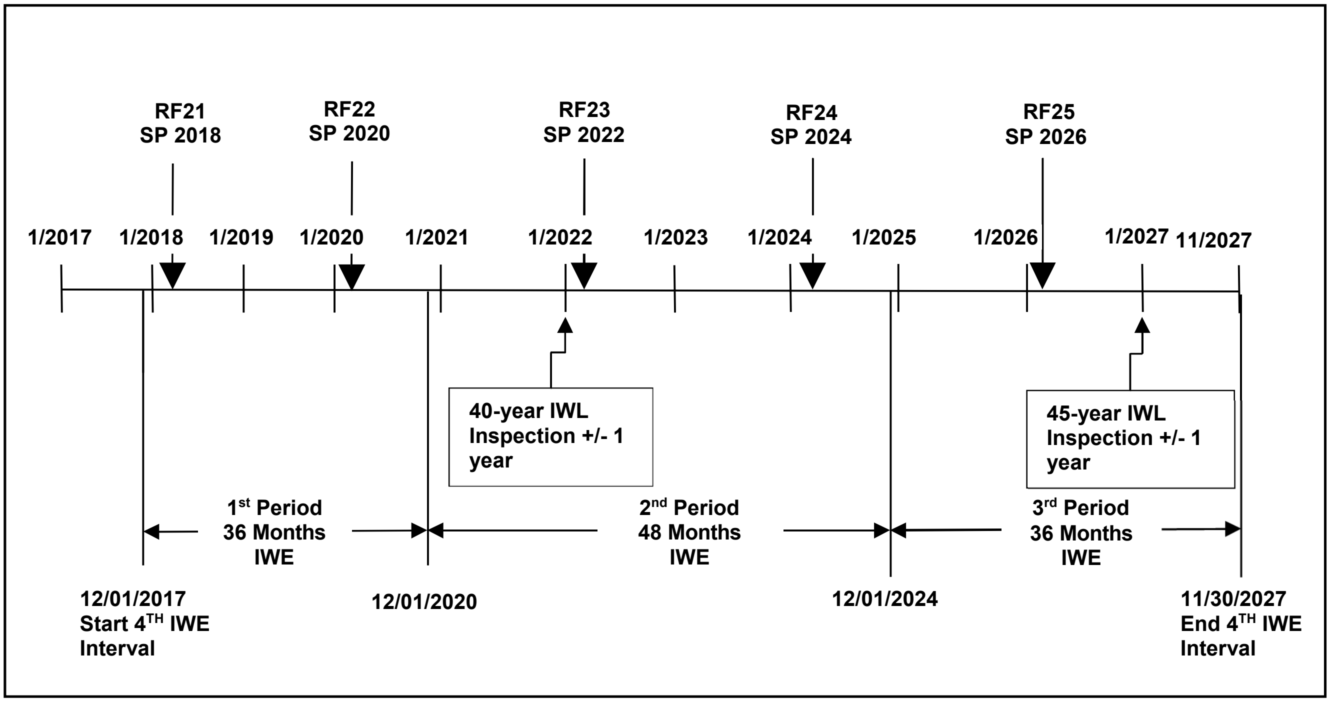
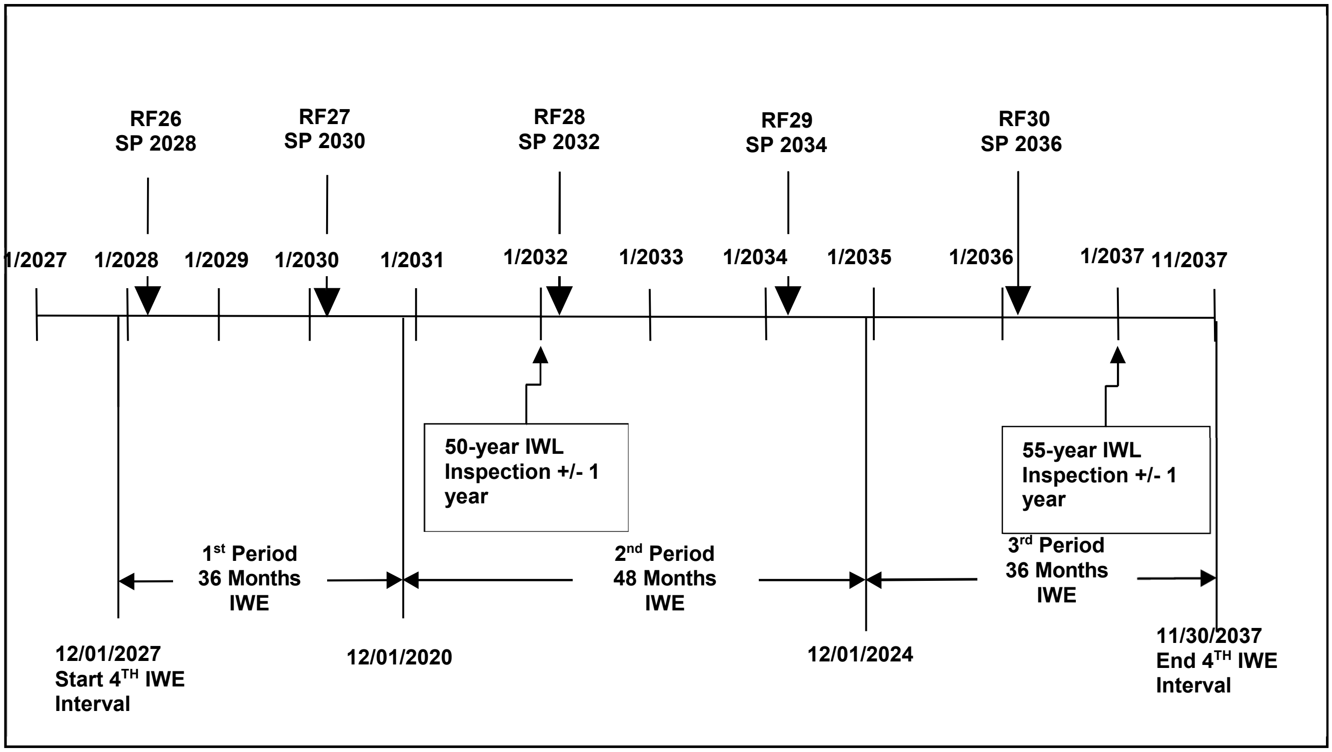


Figure 3.5.4-2 GGNS 5th Interval IWE and IWL Schedule[1]



Note 1: The dates for the 5th Interval IWE and IWL Schedule are proposed as the 5th Interval CISI Program has yet to be developed.

Adoption of Code Cases
Code Cases adopted for ASME Section XI activities for use during the Fourth Ten-year CISI Interval are listed in Table 3.5.4-2. The use of Code Cases is in accordance with ASME Section XI, IWA-2440, 10 CFR 50.55a, and RG 1.147. As permitted by ASME Section XI, RG 1.147 or 10 CFR 50.55a, ASME Section XI Code Cases may be adopted and used as described below:

Adoption of Code Cases Listed for Generic Use in RG 1.147
Code Cases that are listed for generic use in the latest revision of RG 1.147 may be included in the CISI program provided any additional conditions specified in the RG are also incorporated. Table 3.5.4-2 identifies those Code Cases approved for generic use and adopted for the fourth ten-year interval.

Adoption of Code Cases Not Approved in RG 1.147
Certain Code Cases that have been approved by the ASME Board of Nuclear Codes and Standards may not have been reviewed and approved by the NRC staff for generic use and listed in RG 1.147. Use of such Code Cases may be requested in the form of a "Request for Alternative" in accordance with 10 CFR 50.55a(z). Once approved, these Requests for Alternatives will be available for use until such time as the Code Cases are adopted into RG 1.147, at which time compliance with the conditions contained in the RG is required.

Table 3.5.4-3 identifies those Code Cases that have been requested through Requests for Alternatives, as applicable.

<u>Adoption of Code Cases Mandated by 10 CFR 50.55a</u>
The NRC may require the licensee to follow an augmented ISI program for systems and components for which the Commission deems that added assurance of structural reliability is necessary. Many times, these "Augmented Requirements" will be contained in Code Cases that ASME has approved. The NRC may mandate their use and add conditions it believes are necessary via 10 CFR 50.55a(g)(6)(ii). Table 3.5.4-4 will be available to identify Code Cases Mandated by the NRC in the regulation that would affect the CISI Program.

<u>Use of Annulled Code Cases</u>
As permitted by RG 1.147(B), Code Cases that have been adopted for use in the current inspection interval that are subsequently annulled by ASME may be used for the remainder of the interval.

<u>Code Case Revisions</u>
Initial adoption of a Code Case requires use of the latest revision of that Code Case listed in RG 1.147. However, if an adopted Code Case is later revised and approved by the NRC, then either the earlier or later revision may be used as permitted by RG 1.147(B). An exception to this provision would be the inclusion of any conditions on the later revision necessary to enhance safety. In this situation, the condition imposed on the later revision must be incorporated into the program.

<u>Adoption of Code Cases Issued Subsequent to Filing the Containment ISI Plan</u>
Code Cases issued by ASME subsequent to filing the Containment ISI Plan with the NRC may be incorporated within the provisions above by revision to the CISI Plan. Any subsequent Code Cases shall be incorporated into the program and identified in either Table 3.5.4-2 or Table 3.5.4-3, as applicable, prior to their use.

<u>Non-Containment Inservice Inspection Code Cases</u>
Only Code Cases applicable to CISI for Class MC and Class CC are included in Tables 3.5.4-2, 3.5.4-3 and 3.5.4-4.

Table 3.5.4-2, Code Cases Adopted from Regulatory Guide 1.147

Code Case Number	Title	NRC Conditions
N-532-5	Repair/Replacement Activity Documentation Requirements and Inservice Inspection Summary Report Preparation and Submission	None
N-765	Alternative to Inspection Interval Scheduling Requirements of IWA-2430	None

Table 3.5.4-3, Code Cases Adopted Via NRC Approved Requests

Code Case Number	Title	Request for Alternative No.
NA	NA	NA

Table 3.5.4-4, Code Cases Required by 10 CFR 50.55a		
Code Case Number	**Title**	**Notes**
NA	NA	NA

Relief Requests

The 2007 Edition through the 2008 Addenda of ASME Section XI provides the rules for the ISI of nuclear power plants. However, not all requirements of ASME Section XI are applicable, or possible to be performed, at every plant. Therefore, Entergy has reviewed the requirements contained in the 2007 Edition through the 2008 Addenda of Section XI and determined where those requirements are not viable at GGNS. 10 CFR 50.55a provides two options for submission of such determinations to the NRC staff for review and approval.

In cases where Entergy proposes alternatives to ASME Section XI when compliance with the specified requirements would result in hardship or unusual difficulty without a compensating increase in the level of quality and safety, a Request for Alternative as allowed by 10 CFR 50.55a(z), will be submitted to the NRC.

Relief Requests

Table 3.5.4-5 contains an index of Requests for Alternatives and Requests for Relief, which were written in accordance with 10 CFR 50.55a(z) and 10 CFR 50.55a(g)(5)(iii).

Table 3.5.4-5, Fourth Ten-Year CISI Interval Relief Requests			
Relief Request	**Relief Request Description**	**Entergy Correspondence**	**NRC SER Correspondence**
NA	NA	NA	NA

Requests to use Later Edition and Addenda of ASME Section XI

On July 28, 2004, the NRC published RIS 2004-12, "Clarification on Use of Later Editions and Addenda to ASME OM Code and Section XI." This RIS clarifies the NRC position on using Editions and Addenda of Section XI, in whole or in part, later than those specified in the ISI program. If the desired Edition or Addenda are referenced in 10 CFR 50.55a(b)(2), the request is submitted following the guidance of the RIS. These types of requests are not required to demonstrate hardship, difficulty, or provide evidence of quality and safety. They do need to ensure that all related requirements are also used. Requests to use edition and/or addenda of ASME Section XI that are referenced in 10 CFR 50.55a(b)(2) that are later than the initial Code of Record established for the ISI program shall be submitted under the provisions of 10 CFR 50.55a(g)(4)(iv).

ASME Class MC and Class CC Examination Boundaries

This section defines those systems that are designated as ASME Section XI Class MC and Class CC and provides justification for their inclusion or exclusion within the Fourth Ten-Year CISI Program. The 2007 Edition through the 2008 Addenda of the ASME Code, Section XI, defines the inspection requirements for each of the ASME Section XI Code Classes. The Containment ISI Drawings identify the IWE and IWL examination boundaries of the primary containment structure.

ASME Class 1, 2, 3
ASME Section XI Class 1, 2 and 3 piping penetrating the containment vessel are attached to penetration sleeves. The piping is not within the scope of Subsections IWE and IWL. The interface between the Class 1, 2, and 3 piping and the Class MC containment is the weld joining the piping and the penetration sleeve assembly. Class 1, 2 and 3 components and the interfacing welds are inspected in accordance with Subsections IWB, IWC or IWD, as applicable.

ASME Class MC
The entire steel liner of the containment structure and connecting penetrations, appurtenances, and parts which form the containment leak tight boundary are classified as MC components. All items within the IWE program boundary are considered "Class MC" regardless of the construction or design code applicable to the component. This class shall be inspected per the requirements of ASME Section XI, Subsection IWE, Table IWE-2500-1 as modified by 10 CFR 50.55a, Code Cases, or Relief Requests approved by the NRC.

ASME Class CC
The reinforced concrete containment structure is designed to function as the load bearing containment structure. This class shall be inspected per the requirements of ASME Section XI, Subsection IWL, Table IWL-2500-1 as modified by 10 CFR 50.55a, Code Cases, or Relief Requests approved by the NRC.

Exemptions, IWE
The following components (or parts of components) are exempted from the examination requirements of IWE-2000, as specified in IWE-1220:

> Vessels, parts, and appurtenances outside the boundaries of the containment as defined in the Design Specification in accordance with IWE-1220(a). Essentially, only the metallic portions of the containment structure that are either pressure-retaining, provide for a leak-tight membrane, or are load-bearing are considered within the boundary of IWE. All other parts and appurtenances, such as non-pressure-retaining portions of electrical and mechanical penetrations, are exempt.
>
> Embedded or inaccessible portions of containment vessels, parts and appurtenances that met the requirements of the original Construction Code in accordance with IWE-1220(b). Essentially, only the components that are accessible by visual line of site with adequate lighting from permanent vantage points without being obstructed by permanent plant structures, equipment, or components are required to be examined per IWE-1232(c). Embedded parts include those that have been covered with concrete since the construction of the containment.
>
> Portions of containment vessels, parts, and appurtenances that become embedded or inaccessible as a result of vessel repair/replacement activities if the conditions of IWE-1232(a) and (b) and IWE-5220 are met.
>
>> IWE-1232(a)(1) no openings or penetrations are embedded in the concrete;
>>
>> IWE-1232(a)(2) all welded joints that are inaccessible for examination are double butt welded and are fully radiographed and, prior to being covered, are tested for leak tightness using a gas medium test, such as Halide Leak Detector Test;

IWE-1232(a)(3) the vessel is leak rate tested after completion of construction or repair/replacement activities to the leak rate requirements of the Design Specifications, IWE-1232(b).

Portions of Class CC metallic shell and penetration liners that are embedded in concrete or otherwise made inaccessible during construction or as a result of repair/replacement activities are exempted from examination, provided:

IWE-1232(b)(1) all welded joints that are inaccessible for examination are examined in accordance with CC-5520 and, prior to being covered or otherwise obstructed by adjacent structures, components, parts, or appurtenances, are tested for leak tightness in accordance with CC-5536; and

IWE-1232(b)(2) the containment is leak rate tested after completion of construction or repair/replacement activities to the leak rate requirements of the Design Specifications. Additionally, all tests following repair/replacement activities per IWE-5220 are met.

Piping, pumps, and valves that are part of the containment system, or which penetrate or are attached to the containment vessel are specifically exempted from the examination requirements of IWE in accordance with IWE-1220(d). These components shall be examined in accordance with the requirements of Subsections IWB or IWC as appropriate to the classification defined by the Design Specification.

Exemptions, IWL
The following items are exempt from the examination requirements of IWL-2000, as specified in IWL-1100(b) and IWL-1220:

Steel portions not backed by concrete, Shell metallic liners and Penetration liners extending the containment liner through the surrounding shell concrete.

Tendon end anchorages that are inaccessible, subject to the examination requirements of IWL-2521.1: Because of safety or radiological hazards or because of structural obstructions.

Portions of the concrete surface that are covered by the liner, foundation material, or backfill, or are otherwise obstructed by adjacent structures, components, parts or appurtenances.

Application Criteria and Code Compliance
Examination methods, which will be used to satisfy Code examination requirements for nonexempt Class MC and Class CC components, are provided below.

The examinations conducted under the Containment Inservice Inspection Program are performed to meet the requirements of ASME Section XI, Subsections IWE and IWL as modified by 10 CFR 50.55a. The following modifications apply to the ASME Section XI 2007 Edition through 2008 Addenda.

In accordance with 10 CFR 50.55a(b)(2)(viii), Section XI condition: Concrete containment examinations. Applicants or Licensees applying Subsection IWL, 2007 Edition through the latest edition and addenda incorporated by reference in paragraph (a)(1)(ii) of this section, must apply paragraph (b)(2)(viii)(E) of this section.

In accordance with 10 CFR 50.55a(b)(2)(viii)(E), (viii)(E)(1), (viii)(E)(2) and (viii)(E)(3) Concrete containment examinations: Fifth provision. For Class CC applications, the applicant or licensee must evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of or the result in degradation to such inaccessible areas. For each inaccessible area identified, the applicant or licensee must provide the following in the ISI Summary Report required by IWA-6000:

(1) A description of the type and estimated extent of degradation, and the conditions that led to the degradation;

(2) An evaluation of each area, and the result of the evaluation, and;

(3) A description of necessary corrective actions.

In accordance with 10 CFR 50.55a(b)(2)(ix), Section XI condition: Metal containment examinations. "Applicants or licensees applying Subsection IWE, 2007 Edition through the latest edition and addenda incorporated by reference in paragraph (a)(1)(ii) of this section, must satisfy the requirements of paragraphs (b)(2)(ix)(A)(2) and (b)(2)(ix)(B) and (J) of this section."

In accordance with 10 CFR 50.55a(b)(2)(ix)(A)(2), (A)(2)(i), A(2)(ii), and (A)(2(iii), Metal containment examinations: First provision. The applicant or licensee must evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of or could result in degradation to such inaccessible areas. For each inaccessible area identified for evaluation, the applicant or licensee must provide the following in the ISI Summary Report as required by IWA-6000:

(1) A description of the type and estimated extent of degradation, and the conditions that led to the degradation;

(2) An evaluation of each area, and the result of the evaluation, and;

(3) A description of necessary corrective actions.

Note: GGNS will provide the required information above in 10 CFR 50.55a(b)(2)(viii)(E) for the Concrete Containment and in 10 CFR 50.55a(b)(2)(ix)(A)(2) for the Metallic Liner as part of the Owner’s Activity Report (OAR), Form OAR-1 in accordance with NRC approved Code Case N-532-5 in lieu of the ISI Summary Report required in IWA-6000.

In accordance with 10 CFR 50.55a(b)(2)(ix)(B), Metal containment examinations: Second provision. When performing remotely, the visual examinations required by Subsection IWE, the maximum direct examination distance specified in Table IWA-2210-1 may be extended and the minimum illumination requirements specified in Table IWA-2210-1 may be decreased provided that the conditions or indications for which the visual examination is performed can be detected at the chosen distance and illumination.

In accordance with 10 CFR 50.55a(b)(2)(ix)(J), Metal containment examinations: Tenth provision. In general, a repair/replacement activity such as replacing a large containment penetration, cutting a large construction opening in the containment pressure boundary to replace steam generators, reactor vessel heads, pressurizers, or other major equipment; or other similar modification is considered a major containment modification. When applying IWE-5000 to Class MC pressure-retaining components, any major containment modification or repair/replacement, must be followed by a Type A test to provide assurance of both containment structural integrity and leak tight integrity prior to returning to service, in accordance with 10 CFR 50, Appendix J, Option A or Option B on which the applicant's or licensee's Containment Leak-Rate Testing Program is based. When applying IWE-5000, if a Type A, B, or C Test is performed, the test pressure and acceptance standard for the test must be in accordance with 10 CFR Part 50, Appendix J.

Entergy will apply the GGNS 10 CFR 50, Appendix B, Quality Assurance Program to ASME Section XI activities; therefore, the ASME Section XI condition in 10 CFR 50.55a(b)(2)(x) does not apply to GGNS.

In accordance with IWE-2500(a) and IWA-2240, alternative examination methods may be used provided the Authorized Nuclear Inservice Inspector (ANII) is satisfied that the results are demonstrated to be equivalent or superior to the results of the method specified by Subsection IWE. The 2008 Addenda of IWA-2240 must be used in accordance with 10 CFR 50.55a(b)(2)(xix), which states, in part:

> 10 CFR 50.55a(b)(2)(xix) Section XI condition: Substitution of alternative methods. The provisions in IWA-4520(b)(2) and IWA-4521 of the 2008 Addenda through the latest edition and addenda incorporated by reference in paragraph (a)(1)(ii) of this section, allowing the substitution of ultrasonic examination for radiographic examination specified in the Construction Code, are not approved for use.

IWE Examinations

Personnel performing IWE examinations shall be qualified in accordance with written procedures prepared as required by IWE-2300, Entergy's Written Practice "Administration and Control of ENS NDE," or approved vendor written practice for certification and qualification of NDE personnel.

General Visual Examinations per IWE-2311 are conducted to assess the general condition of containment surfaces. General visual examination shall be performed with adequate illumination to detect evidence of degradation. General Visual Examinations for Subsection IWE shall be performed in accordance with Entergy Procedure "Visual Examinations of Class MC Components." The requirements of IWA-2210 are not applicable to Subsection IWE General Visual Examinations.

VT-3 Visual Examinations per IWE-2312 are conducted to access the condition of wetted surfaces of submerged areas and to access the condition of vent system surfaces of BWR containments.

VT-1 Visual Examinations per IWE-2313 are conducted:

(1) to access the initial condition of surfaces requiring augmented examinations in accordance with IWE-1241 and to determine the magnitude and extent of any deterioration and distress of these surfaces during subsequent augmented examinations

(2) to determine the condition of inaccessible areas [IWE-1232(c)] when conditions are initially detected in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas; and

(3) In accordance with IWE-2500 and Table IWE-2500-1, Examination Category E-G, to access the condition of containment pressure retaining bolting.

If a volumetric examination is performed to detect discontinuities in the volume of a material and material thickness, the Ultrasonic (UT) examinations shall be conducted as required using ultrasonic thickness measurement method specified in ASME Boiler and Pressure Vessel Code Section XI, Appendix I.

When ultrasonic thickness measurements are performed, grids not exceeding one-foot square shall be used. The number and location of the grids shall be determined by the CISI Program Owner.

Ultrasonic thickness measurements shall be used to determine the minimum wall thickness within each grid. The location of the minimum wall thickness within each grid shall be marked or recorded such that periodic re-examination can be performed in accordance with the requirements of Table IWE-2500-1, Examination Category E-C. A sampling plan may be used to determine the number and location of ultrasonic thickness measurement grids within each contiguous examination area provided. The UT examinations shall be performed utilizing either manual or mechanized UT techniques.

When access or other conditions prevent direct examination, remote visual examination can be substituted for direct examination provided that the requirements of IWA-2211(g) and IWA-2213(g) are met. IWA-2211(g) and IWA-2213(g) require that the selected test characters of Table IWA-2211-1 can be resolved as a part of the remote examination procedure demonstration. Additionally, the remote examination system shall have the capability of distinguishing and differentiating between the colors applicable to the component examination being conducted. Remote visual examination aids include but are not limited to mirrors, telescopes, periscopes, borescopes, fiber optics, and Closed-Circuit Television (CCTV) systems with or without permanent recording capabilities. Reference 10 CFR 50.55a Limitations and Modifications addressing 10 CFR 50.55a (b)(2)(ix)(B), when performing remotely, the visual examinations required by Subsection IWE for use of maximum direct examination distance specified in Table IWA- 2210-1 and the minimum illumination requirements specified in Table IWA- 2210-1.

<u>IWL Examinations</u>
Personnel performing IWL examinations shall be qualified in accordance with written procedures prepared as required by IWL-2300, Entergy's Written Practice "Administration and Control of ENS NDE," or approved vendor written practice for certification and qualification of NDE personnel.

General Visual examinations IWL-2310(a) of concrete surfaces shall be performed to assess the general structural condition of containments. The general visual examination shall be performed in sufficient detail to identify areas of concrete deterioration and distress, such as described in ACI 201.1 and ACI 349.3R. General Visual Examinations for Subsection IWL shall be performed in accordance with Entergy's "General and Detailed Visual Examinations of Concrete Containments." The requirements of IWA-2210 are not applicable to Subsection IWL General Visual Examinations.

Detailed Visual examinations per IWL-2310(b) are conducted to determine:

(1) the magnitude and extent of deterioration and distress of suspect concrete surfaces initially detected by general visual examinations;

(2) the magnitude and extent of deterioration and distress of suspect concrete surfaces, at tendon anchorage areas, initially detected by general visual examinations;

(3) the condition (e.g., cracks, wear, or corrosion) of tendon wires or strands, and anchorage hardware, as described in IWL-2524.1;

(4) the condition of concrete surfaces affected by repair/replacement activities, in accordance with IWL-5250; and

(5) the condition of reinforcing steel exposed as a result of removal of defective concrete as described in IWL-4220(c).

Detailed Visual Examinations for Subsection IWL shall be performed in accordance with Entergy's "General and Detailed Visual Examinations of Concrete Containments." The requirements of IWA-2210 are not applicable to Subsection IWL, Detailed Visual Examinations.

<u>Examination Category IWE</u>
The following provides a summary of the application of ASME Code Section XI, 2007 Edition through the 2008 Addenda to the GGNS, Unit 1, Ten-Year Program for the Fourth Inspection Interval. The application and distribution of examinations for this interval is defined by paragraph IWE-2411 of ASME Section XI.

The results of this application are summarized by ASME Section XI Category and Item Number and are contained within Table 3.5.4-6. Table 3.5.4-6 only contains those ASME Item Numbers that are relevant to GGNS.

IWE Program Boundary

The IWE program boundary, covering inservice inspection and repair and replacement, is defined in accordance with IWE-1100 as determined by Class MC pressure retaining components and their integral attachments required by the applicable provisions of 10 CFR 50.55a(g)(4)(v).

10 CFR 50.55a(g)(4)(v)(A), Metal and concrete containments: First provision – Requires the boundary to include:

> Metal containment pressure retaining components and their integral attachments must meet the inservice inspection, repair, and replacement requirements applicable to components that are classified as ASME Code Class MC.

10 CFR 50.55a(g)(4)(v)(B), Metal and concrete containments: Second provision – Requires this boundary to include:

> Metallic shell and penetration liners that are pressure retaining components and their integral attachments in concrete containments must meet the inservice inspection, repair, and replacement requirements applicable to components that are classified as ASME Code Class MC.

<u>Inspection Intervals – Subsection IWE</u>
IWA-2430(a), (b), (d), and (e) shall be used as required for IWE inspections in accordance with ASME Section XI, 2007 Edition through the 2008 Addenda. The applicable alternative requirements of NRC-approved Code Case N-765 will be used in lieu of the requirements of IWA-2430(c). All Subsection IWE examinations shall be completed during each of the inspection intervals for the service lifetime of the power unit. The inspection program shall conform to IWA-2431 with the alternatives to IWA-2430(c) from Code Case N-765.

IWA-2430

(a) The inservice examinations and system pressure tests required by IWB, IWC, IWD, IWE, and inservice examinations and tests of IWF shall be completed during each of the inspection intervals for the service lifetime of the plant. The inspections shall be performed in accordance with the schedule of the Inspection Program of IWA-2431.

(b) The inspection interval shall be determined by calendar years following placement of the plant into commercial service.

(c) In addition to IWA-2430(c), for plants that are out of service continuously for 6 months or more, the inspection interval during which the outage occurred may be extended for a period equivalent to the outage and the original pattern of intervals extended accordingly for successive intervals.

(d) The inspection intervals for items installed by repair/replacement activities shall coincide with remaining intervals, as determined by the calendar years of plant service at the time of the repair/replacement activities.

Code Case N-765 Alternatives for IWA-2430(c)

(a) Each Inspection interval may be extended by as much as one year, and may be reduced without restriction, provided the examinations required for the interval have been completed. Successive intervals shall not extend more than one year beyond the original pattern of ten-year intervals, and shall not exceed eleven years in length. For extended intervals, neither the start and end dates nor the inservice inspection program for the successive interval need be revised.

(b) Examinations may be performed to satisfy the requirements of an extended interval in conjunction with examinations performed to satisfy the requirements of the successive interval. However, an examination performed to satisfy requirements of either the extended interval or the successive interval shall not be credited to both intervals.

(c) That portion of an Inspection interval described as an inspection period may be extended by as much as one year, and may be reduced without restriction, provided the examinations required for that period have been completed. This adjustment shall not alter the requirements for scheduling Inspection Intervals.

(d) The Inspection Interval for which an examination was performed shall be identified on examination records.

Inspection Schedule – Subsection IWE

Per IWA-2420, inspection plans and schedules shall be prepared for the first inservice inspection interval and subsequent inservice inspection intervals. Per IWA-2420(b), an implementation schedule for performance of examinations and tests shall be prepared for each inspection plan.

Per Code Case N-765, each Inspection interval may be extended by as much as one year, and may be reduced without restriction, provided the examinations required for the interval have been completed. Successive intervals shall not extend more than one year beyond the original pattern of ten-year intervals, and shall not exceed eleven years in length. For extended intervals, neither the start and end dates nor the ISI program for the successive interval need be revised.

Per IWA-2430(d), in addition to Code Case N-765, for plants that are out of service continuously for 6 months or more, the inspection interval during which the outage occurred may be extended for a period equivalent to the outage and the original pattern of intervals extended accordingly for successive intervals.

Subarticle IWE-2400 includes the requirements for the scheduling of examination and tests for Class MC Components and Metallic Liners of Class CC components.

Specific scheduling criteria are included in IWE-2411. This paragraph references Table IWE-2411-1, which includes minimum and maximum percentages of examinations required to be completed by each inspection period.

Per IWE-2411(a), examinations listed in Table IWE-2500-1 as deferrable to the end of the inspection interval, are not required to meet the criteria in Table IWE-2411-1.

Per IWE-2420(a), the sequence of component examinations established during the first inspection interval shall be repeated during each successive inspection interval, to the extent practical. The sequence of component examinations may be modified in a manner that optimizes scaffolding, radiological, insulation removal, or other considerations, provided that the percentages of IWE-2411-1 are maintained.

IWE Examination Category E-A – Containment Surfaces

Examination Category E-A of the ASME Code Section XI, 2007 Edition through the 2008 Addenda, requires examination of Class MC "Metallic Containment" pressure-retaining components and their integral attachments, as well as, the metallic shell and penetration liners of Class CC "Concrete Containment" pressure-retaining components and their integral attachments.

Containment vessel pressure retaining boundary accessible surface areas and wetted surfaces of submerged areas, shall be examined in accordance with Table IWE-2500-1, Examination Category E-A. The accessible surface areas and wetted surfaces of submerged areas are identified in the Containment ISI drawings listed in Appendix A. Identifiers for these IWE components are included in the applicable database.

Note: Category E-A, Item No. E1.20 refers to the BWR vent systems accessible surface areas and is not applicable to GGNS. Category E-A, Item No. E1.30 identifies Moisture Barriers. The design of GGNS does not include moisture barriers. As a result, no moisture barrier examinations are required.

10 CFR 50.55a Limitations and Modifications

The requirements of Table IWE-2500-1, Examination Category E-A, are modified by 10 CFR 50.55a as follows:

Per 10 CFR 50.55a(b)(2)(ix)(B), Metal containment examinations: Second provision. When performing remotely the visual examinations required by Subsection IWE, the maximum direct examination distance specified in Table IWA-2210-1… may be extended and the minimum illumination requirements specified [in Table IWA-2210- 1] may be decreased provided that the conditions or indications for which the visual examination is performed can be detected at the chosen distance and illumination.

Acceptance Criteria – IWE-3510

Acceptance of general visual examinations is accomplished by an acceptance review by the Responsible Individual (RI) in accordance with IWE-3511 for Coated and Noncoated areas and IWE-3513 for Visual Examination, VT-3.

IWE Examination Category E-C – Containment Surfaces Requiring Augmented Examination

Containment surface areas subject to accelerated degradation and aging require the augmented examinations identified in Table IWE-2500-1, Examination Category E-C. In accordance with IWE-2420(b), examinations accepted by evaluation per IWE-3000 shall be examined under Category E-C in the next inspection period. These areas shall be listed in the applicable database as Category E-C, Item Number E4.11 and/or E4.12 as follows:

For surfaces where the side requiring augmented examination is not accessible for visual examination, ultrasonic thickness measurements shall be performed in accordance with Examination Category E-C, Item No. E4.12, and in accordance with IWE-2500(b)(2), IWE-2500(b)(3), and IWE-2500(b)(4).

The examination(s) must be performed once per period until the areas examined remain essentially unchanged for the next inspection period. In accordance with Table IWE-2500 1, Examination Category E-C, Note 2 and IWE-2420(d), if the areas examined remain essentially unchanged, they no longer require Examination Category E-C examination.

Identification of IWE Augmented Examination of Containment Surface Areas – Examination Category E-C.

Whenever GGNS has an area(s) requiring examination under Category E-C, the area shall be identified in the applicable database.

Tracking of IWE Augmented Examination Areas

IWE-1241 requires augmented examination of surface areas subject to accelerated degradation and aging identified in Table IWE-2500-1, Examination Category E-C, or interior and exterior surface areas accepted by evaluation as specified in IWE-2420(b).

When it is determined that a given surface area requires augmented examination, the area shall be added to the applicable database. Areas added to the augmented examination table due to the provisions of IWE-2420(b) may be removed from the database when the provisions of IWE- 2420(c) have been met.

Augmented examination areas added to the applicable database table due to the provisions of IWE-1241(a), (b) or (c) may be removed and/or deactivated from the database only after determination that the area is no longer subject to accelerated degradation and aging as described in IWE-1241(a), (b) or (c), as applicable.

Removal and/or deactivation of areas from the database shall be documented as required by Entergy's control procedures.

Acceptance Criteria – IWE-3520

Acceptance for augmented areas is accomplished by an acceptance review by the RI per the requirements of IWE-3521, for Visual Examination, VT-1 and IWE-3522, for Ultrasonic Examination.

IWE Examination Category E-G – Pressure Retaining Bolting

Examinations shall include bolts, studs, nuts, bushings, washers, and threads in base material and flange ligaments between fastener holes. Examination may be performed with the connection assembled and bolting in place under tension, provided the connection is not disassembled during the interval. If the bolted connection is disassembled for any reason during the interval, the examination shall be performed with the connection disassembled.

Acceptance Criteria – IWE-3530

Acceptance of VT-1 visual examinations is accomplished by an acceptance review by the RI per the requirements of IWE-3531, for Visual Examination, VT-1.

Table 3.5.4-6, GGNS Unit 1 Code Category IWE Summary

Category	Item Number	Description	Exam Method	Number of Components in Item No.	Required to be Examined During Interval	Examination Percentage Required	Number Examined or Scheduled During the Interval	Number to be Examined in First Period	Number to be Examined in Second Period	Number to be Examined in Third Period
E-A, Containment Surfaces										
E-A	E1.11	Containment Vessel Pressure Retaining Boundary Accessible Surface Areas[(1)]	General Visual	55	165[(2)]	100%	Each Inspection Period	55	55	55
E-A	E1.12	Containment Vessel Pressure Retaining Boundary Wetted Surfaces of Submerged Areas	VT-3	16	16	100%	16	0	0	0
			Category Total	**71**	**181[(2)]**			**55**	**55**	**71**
Notes for Cat. E-A	Note 1: Examinations shall include all accessible interior and exterior surfaces of Class MC components, parts, and appurtenances, and metallic shell and penetration liners of Class CC components. Note 2: Examination of this item number is required each period. Therefore, the number required during the interval is three times the total number of components. This is also reflected in the category total.									

Table 3.5.4-6, GGNS Unit 1 Code Category IWE Summary										
Category	Item Number	Description	Exam Method	Number of Components in Item No.	Required to be Examined During Interval	Examination Percentage Required	Number Examined or Scheduled During the Interval	Number to be Examined in First Period	Number to be Examined in Second Period	Number to be Examined in Third Period
E-C, Containment Surfaces Requiring Augmented Examination										
E-C	E4.11	Containment Surface Areas Visible Surfaces	VT-1	0	0(1)	100%	100% of surface areas identified IWE-1242(1)	0	0	0
E-C	E4.12	Containment Surface Areas Surface Area Grid Minimum Wall Thickness Location	Ultrasonic Thickness	0	0(2)	100%	100% of minimum wall thickness locations during each inspection period(2)	0	0	0
Category Total				**0**	**0**			**0**	**0**	**0**
Notes for Cat. E-C	Note 1: Containment surface areas requiring augmented examinations are those identified in IWE-1240. GGNS currently does not have any containment surface areas requiring augmented examinations during the Fourth Interval. Note 2: The extent of examination shall be 100% for each inspection period until the areas examined remain essentially unchanged for the next inspection period. Such areas no longer require augmented examination in accordance with IWE-2420(c).									

Table 3.5.4-6, GGNS Unit 1 Code Category IWE Summary										
Category	Item Number	Description	Exam Method	Number of Components in Item No.	Required to be Examined During Interval	Examination Percentage Required	Number Examined or Scheduled During the Interval	Number to be Examined in First Period	Number to be Examined in Second Period	Number to be Examined in Third Period
E-G, Pressure Retaining Bolting										
E-G	E8.10	Bolted Connections(1)(2)	VT-1	23	23	100%	100% of Each bolted connection	0	0	23
			Category Total	**23**	**23**			**0**	**0**	**23**
Notes for Cat. E-G	Note 1: Examination shall include bolts, studs, nuts, bushings, washers, and threads in base material and flange ligaments between fastener holes. Note 2: Examination may be performed with the connection assembled and bolting in place under tension, provided the connection is not disassembled during the interval. If the bolted connection is disassembled for any reason during the interval, the examination shall be performed with the connection disassembled.									

Examination Category IWL

The following provides a summary of the application of ASME Code Section XI, 2007 Edition through the 2008 Addenda, to the GGNS Unit 1, Ten-Year Program for the Fourth Inspection Interval. The application and distribution of examinations for this interval are defined by IWL-2410 of ASME Section XI.

The results of this application are summarized by ASME Category and Item Number and are contained within Table 3.5.4-7. This table only contains those ASME Item Numbers that are relevant to GGNS.

IWL Program Boundary

The IWL program boundary, covering inservice inspection and repair and replacement, is defined in accordance with IWL-1100 as determined by Class CC for the reinforced concrete and post-tensioning systems and components required by the applicable provisions of 10 CFR 50.55a(g)(4)(v).

10 CFR 50.55a(g)(4)(v)(C) Metal and concrete containments Third provision – Requires this boundary to include:

Concrete containment pressure retaining components and their integral attachments, and the post-tensioning systems of concrete containments, must meet the inservice inspections, repair, and replacement requirements applicable to components that are classified as ASME Code Class CC.

Inspection Periods – Subsection IWL

IWA-2430(g) states: the inspection intervals for inservice examination of Class CC components shall be in accordance with the requirements of IWL-2400. Subarticle IWL-2400 includes the requirements for the scheduling of examination and tests for Class CC Concrete components.

Concrete Examinations

Concrete examinations shall be conducted every 5 years (a period) as described in IWL-2410(a), (b) and (c). For the purposes of this program section, an IWL inspection period shall be defined as the window of time allowed by IWL-2410 for the completion of one set of IWL examinations.

Concrete surface areas affected by repair/replacement activities shall be examined in accordance with IWL-2410(d).

IWL Concrete Containment Surfaces – Examination Category L-A

Accessible concrete containment surfaces shall be examined in accordance with Table IWL-2500-1, Examination Category L-A. The accessible surface areas for GGNS are identified in the Containment ISI drawings.

In accordance with Table IWL-2500-1, Examination Category L-A, Item No. L1.11, a General Visual examination of concrete surfaces shall be performed once every 5 years (+ 1 year).

In accordance with Table IWL-2500-1, Examination Category L-A, Item No. L1.12, a Detailed Visual examination of suspect concrete surface areas shall be performed once per inspection period (5 years).

Identifiers for these IWL components are included in the database for GGNS.

Acceptance Criteria – IWL-3211

The condition of the concrete surface and tendon end anchorage areas is acceptable if the Responsible Engineer determines that there is no evidence of damage or degradation, corrosion protection medium leakage, or end-cap deformation sufficient to warrant further evaluation or performance of repair/replacement activities.

IWL Unbonded Post-Tensioning System – Examination Category L-B

The containment structure at GGNS does not contain an unbonded post-tensioning system; therefore, Examination Category L-B, Item Nos. L2.10, L2.20, L2.30, L2.40, and L2.50 are not applicable at GGNS.

Table 3.5.4-7, GGNS Unit 1 Code Category IWL Summary									
Category	Item Number	Description	Exam Method	Number of Components in Item No.	Required to be Examined During Interval	Examination Percentage Required	Number Examined or Scheduled During the Interval	Number to be Examined in Second Period(3)	Number to be Examined in Third Period(3)
L-A, Concrete									
L-A	L1.11	Concrete surface All accessible surface areas(1)	General Visual	36	72(2)	Every five years	IWL-2410	0	0
L-A	L1.12(4)	Concrete Surface, Suspect areas	Detailed Visual	N/A	N/A	N/A	N/A	N/A	N/A
Category Total				**36**	**72(2)**			**36**	**36**
Notes for Cat. L-A	Note 1: Includes concrete surfaces at tendon anchorage areas not selected by IWL-2521 or exempted by IWL-1220(a). Note 2: IWL-2410 requires 100% examination every five years. Therefore, the number required during the interval is twice the total number of components. This is also reflected in the category total. Period 2 (40-year inspection) and Period 3 (45-year inspection) only. Note 3: For the purposes of the CISI Program, an IWL inspection period is five years, with two periods per inspection interval. Note 4: GGNS currently does not have any suspect areas to be examined during the Fourth Interval.								

Evaluations

If examination results require evaluation, the evaluation and associated report shall be performed in accordance with ASME Section XI, 2007 Edition with 2008 Addenda, Articles IWE-3000 and IWL-3000, and the regulatory amendments in 10 CFR 50.55a. Evaluations shall be performed by the Responsible Individual (RI) for IWE and by the Registered Professional Engineer (RPE) for IWL.

Acceptance of components for continued service shall be subject to the rules of Articles IWE-3000 and IWL-3000.

Acceptance Reviews

Unlike Subsections IWB, IWC, and IWD; Subsections IWE and IWL do not provide detailed acceptance standards for many of the required examinations. Instead, IWE-3500 specifies that the owner shall define the acceptance criteria for many of the examinations, while IWL-3211 relies on the Responsible Engineer (RE) to determine the acceptance standards based on plant design and guidance provided in IWL-2510.

With the exception of wall thickness criteria mentioned in IWE-3122.3(a) and IWE-3522, no numerical acceptance standards are provided for Class MC components by IWE. Similarly, with the exception of values provided for unbonded post-tensioning systems in IWL-3220, numerical acceptance standards are not provided for Class CC components by IWL.

Entergy will ensure that this standard is met by having a RE conduct acceptance reviews of examination results. The requirement to conduct an acceptance review does not prohibit the RE from personally performing the examination.

In lieu of detailed acceptance criteria, IWE and IWL will rely on the expertise and engineering judgment of the RE to detect conditions, which could affect the leak tightness or structural integrity of the containment or prevent an inspected component from performing its intended function to protect containment integrity. The acceptance review criteria are as follows:

Screening Criteria

The RE may designate screening criteria for a particular examination method and/or a particular component. Screening criteria provide the examiner with RE guidance on indications that are not relevant to the acceptance review. Unless specified within the screening criteria, indications that are less severe than the screening criteria are not required to be reported on the examination record and do not require RE acceptance review.

Conduct of Acceptance Reviews for Class MC Components

The RE reviews the examination data for:

(a) Conditions which could affect the leak tightness or structural integrity of the containment or prevent an inspected component from performing its intended function to protect containment integrity;

(b) Conditions which would violate the design basis of the containment;

(c) Conditions in accessible areas, which could indicate the presence of or result in degradation of inaccessible areas.

RE Evaluation

If the RE determines the leak tightness or structural integrity of containment could be compromised by the indicated condition or that a non-structural component (such as a seal, gasket, or moisture barrier) may not carry out its intended containment function, then:

(a) The item is not acceptable for continued service without further evaluation.

(b) The RE (or designee) shall prepare a condition report. As a minimum the corrective actions shall include an evaluation of:

  (1) The acceptability of the item for continued service;

  (2) The nature and extent of any required repairs or replacements;

  (3) Whether additional component examinations are required.

RE Input to OAR-1

The RE (or designee) shall provide inputs to the OAR-1 form for each flaw or area of degradation in accordance with the rules outlined in this Program Section.

RE Examination Category E-C Determination

For surface areas, if the flaw or area of degradation fails to meet the acceptance criteria of IWE-3000, then the RE shall add the item to the Examination Category E-C Component List in the applicable database.

Degradation in Inaccessible Areas

If the RE determines the examination reveals conditions, which could indicate the presence of or result in degradation of inaccessible areas then:

(a) The RE (or designee) shall prepare a Condition Report to evaluate the acceptability of the inaccessible area in question.

(b) The RE (or designee) shall provide inputs to the OAR-1 for each inaccessible area identified above to include:

(1) A description of the type and estimated extent of degradation and the conditions that led to the degradation;

(2) An evaluation of each area, and the results of the evaluation; and,

(3) A description of necessary corrective actions.

(c) If the RE (or designee) determines the examination reveals surface areas likely to experience accelerated degradation as described in IE-1241 then the RE shall add the item to the Examination Category E-C Component List.

Conduct of Acceptance Reviews for Class CC Concrete Surfaces

The RE reviews the examination data for:

(a) Conditions which could affect the leak tightness or structural integrity of the concrete containment;

(b) Conditions which would violate the design basis of the containment;

(c) Conditions in accessible areas which could indicate the presence of or result in degradation of inaccessible areas.

RE Evaluation

If the RE determines that the item cannot be accepted by examination in accordance with IWL-3211, then:

(a) The item is not acceptable for continued service without further evaluation.

(b) The RE (or designee) shall prepare a condition report. As a minimum, the corrective actions shall include completion of the Engineering Evaluation report required by IWL-3300. This report documents requirements of IWL-3310:

(1) The cause of the condition, which does not meet the acceptance standards;

(2) The applicability of the condition to any other plants at the same site;

(3) The acceptability of the concrete containment without repair of the item;

(4) Whether or not repair/replacement is required and, if required, the extent, method, and completion date for the repair/replacement activity;

(5) Extent, nature, and frequency of additional examinations.

(c) If the RE determines the examination reveals conditions, which could indicate the presence of or result in degradation of inaccessible areas, then:

(1) The RE (or designee) shall prepare a Condition Report to evaluate the acceptability of the inaccessible area in question.

(2) The RE (or designee) shall provide inputs to the OAR-1 or each inaccessible area identified above to include:

(i) A description of the type and estimated extent of degradation, and the conditions that led to the degradation;

(ii) An evaluation of each area, and the results of the evaluation; and,

(iii) A description of necessary corrective actions.

Successive Inspections

Successive Inspections are performed in accordance with IWE-2420 when a Class MC component is accepted for continued service per IWE-3122.3. These Class MC components are examined in accordance with Table IWE-2500-1, Category E-C.

Successive Inspections are not performed on Class CC concrete components.

Plant specific successive inspections are included in the applicable database module for each plant.

Supplemental Examinations

Supplemental Examinations are performed in accordance with IWE-3200 when a Class MC component is accepted for continued service per IWE-3122.3. These Class MC components are examined in accordance with Table IWE-2500-1, Category E-C.

Successive Inspections are not performed on Class CC concrete components.

Plant specific successive inspections are included in the applicable database module for each plant.

Repair/Replacements

Program requirements for repairs and replacements of containment items are controlled in accordance with the ASME Section XI, Repair and Replacement Program and IWA-4000. 10 CFR 50.55a(b)(2)(ix)(J) contains specific requirements for modifications replacing penetrations or removing portions of the steel liner.

When a vessel, liner, or a portion thereof is subjected to a repair/replacement activity during the service lifetime of a plant, the preservice examination requirements for the portion of the vessel affected by the repair/replacement activity shall be met.

> For IWE and IWL, preservice examination of repair/replacement activities shall be performed upon completion of the activity. If the repair/replacement activity is performed while the plant is not in service, the preservice examination shall be performed prior to resumption of service. [Reference ASME Section XI, IWA-4530 and IWL-2230(b)]
>
> For IWL only, when the repair/replacement activity is performed while the plant is in service, the preservice examination may be deferred to the next scheduled outage. [Reference ASME Section XI IWL-2230(c)]. Deferral of preservice for IWE is not permissible.
>
> When a system leakage test is required by IWE-5220, the preservice examination may be performed either prior to or following the test.

Welds made as part of repair/replacement activities shall be examined in accordance with the requirements of IWA-4000, except that for welds joining Class MC or Class CC components to items designed, constructed, and installed to the requirements of Section III, Class 1, 2, or 3, the examination requirements of IWB-2000, IWC-2000, or IWD-2000, as applicable, shall also apply.

Preservice examination for a repair/replacement activity may be conducted prior to installation provided:

> The examination is performed after the pressure test required by the Construction Code has been completed;
>
> The examination is conducted under conditions and with equipment and techniques equivalent to those that are expected to be employed for subsequent inservice examinations; and,
>
> The shop or field examination records are, or can be, documented and identified in a form consistent with that required by IWA-6000.

When a concrete containment or a portion thereof is corrected or modified by repair/ replacement activities during the service lifetime of a plant, the preservice examination requirements shall be met for the repair/replacement activity.

Pressure Testing

Program requirements for pressure testing of containment items, addressed in IWE-5000 and IWL-5000, are controlled in accordance with the requirements contained in 10 CFR 50, Appendix J. Pressure tests following repair/replacement activities shall be performed in accordance with IWE-5220.

Records and Reports

Examination and test records and documented evaluation reports provide the basis for comparison with previous results and subsequent inspections. In accordance with Section XI, IWA-6000, these records and reports shall be maintained for the service lifetime of the component or system. Records and reports for the CISI Program, outage examination schedules, examination results, procedures, certifications, test, repairs, and replacements are maintained in accordance with Entergy procedures, and meet the requirements of ASME Section XI, Article IWA-6000 and Code Case N-532-5.

IWE and IWL inspection and testing information shall be included in the ISI Summary Report required by Article IWA-6000 and the regulatory amendments in 10 CFR 50.55a. IWE and IWL repair and replacement information shall be included in the Owner's Report for Repair/Replacement Activities required by Subarticle IWA-6000 and as modified by Code Case N-532-5. Form OAR-1 includes ASME activities performed during the outage and the previous operating cycle. Code Case N-532-5 requires completion of the OAR-1 within 90 calendar days after completion of each refueling outage. Form OAR-1 is prepared, maintained, and submitted in accordance with Program Section CEP-RR-001, "ASME Section XI Repair/Replacement Program."

Form NIS-2A documents Repair/Replacement activities performed during the outage and the previous operating cycle. Form NIS-2A is prepared and maintained in accordance with ASME Section XI Repair/Replacement Program.

3.5.5 RF20 Summary of Examinations

Suppression Pool Liner Inspection

The indications documented in RF-20 for the suppression pool liner were acceptable by examination in accordance with the requirements of ASME Section XI, Subsection IWE based on the following:

For area 1, the area containing the worst-case thickness loss, additional UT thickness measurements were obtained during RF20 and reported. While additional UT thickness were not available for the remaining areas, extensive UT thickness measurements of the suppression pool liner were obtained in 2007 to support evaluation of indications detected in 2007. The minimum wall thickness recorded for the suppression pool liner was 0.272" with the majority of readings between 0.278" and 0.295" in thickness. For the purposes of this review, the thickness is assumed to be the minimum of 0.272" for all areas except area 1 in Table 3.5.5-1 below. For area 1, the minimum thickness reported is used for the general area plate thickness.

Table 3.5.5-1 VT-3 of GGNS Suppression Pool Liner in RF20			
Area	Recorded Plate Thinning	UT Thickness	Minimum Plate Thickness
1	0.055"	0.315"	0.260"
2	<0.030"	0.272"	>0.242"
3	<0.012"	0.272"	>0.260"
4	<0.011"	0.272"	>0.261"
5	<0.009"	0.272"	>0.263"

For areas 1, 3, 4, and 5, the minimum plate thickness remains above the nominal plate thickness of 0.250".

For area 2, the minimum plate thickness is above the minimum thickness of 0.225".

All the noted indications are small, localized rounded indications, which do not result in a plate thickness below the allowable plate thicknesses. As a result, these areas are accepted by examination in accordance with ASME IWE-3122.1 (2001 Edition with 2003 Addenda).

Results of IWE inspection prior to RF20

The IWE inspection prior to the IWE inspection of RF20 were performed during RF19. The results of this inspection were characterized as "Items were previously identified and evaluated. No additional degradation noted."

In support of the results of the RF19 IWE inspection as stated above, the inspection items identified during the RF19 inspection are provided in Table 3.5.5-2. The RF20 IWE inspection results provided in Table 3.5.5-2 are also provided with the addition of the inspection component identification to permit the comparison of the RF19 and RF20 inspections.

Results of the last two IWL inspections

The last two IWL inspections were performed in RF20 and RF18. The results of these inspections were characterized as "Indications were previously identified and evaluated with no changes."

In support of the results of the RF20 and RF18 IWL inspections as stated above, the inspection items identified during the RF20 and RF18 inspections are provided in Attachment 2. The inspection results are also provided with the corresponding inspection component identification to permit the comparison of the RF20 and RF18 inspections.

Table 3.5.5-2, Containment Visual Inspection (IWE)			
Component ID / Report No.	**Indication Description**	**Disposition**	**Comments**
RF20, March 2016			
Suppression Pool Underwater Surfaces			
1-FP-02F-2	Dent Indication. Random mechanical (mech.) damage affecting substrate-30 Count-0.25 in. dia. per Indication, In. x In. area. Metal loss 55 mils.	Report to Engineering	Approved
1-FP-08A-1	Other Indication. Random mech. damage affecting substrate-1 Count-0.125 in. x 2 in. per Indication, in. x in. area. Metal loss <11 mils	Report to Engineering	Approved
1-FP-08A-1	Dent Indication. Random mech. damage affecting substrate-1 Count-0.25 in. dia. per Indication, in. x in. area. Metal loss <30 mils	Report to Engineering	Approved
1-FP-040-4	Other indication. Random mech. damage affecting substrate-0.0625 in. x 10 in. per Indication, in. x in. area affected, 4 Per Sq. Ft. Metal loss <9 mils	Report to Engineering	Approved
1-WP-01C-3	Other Indication. Isolated mech. damage affecting substrate-0.25 in. dia. per Indication, 8 in. x 3 in. area affected, 9 Per Sq. Ft. Metal loss <12 mils	Report to Engineering	Approved
Containment Building Liner			
Liner 93-1 ISI-VT-16-060	Uncoated surface, 3 places, light rust on liner weld, no evidence of pitting. Uncoated surface at liner weld. Light rust with no evidence of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.
Liner 93-2 ISI-VT-16-061	Uncoated surface with light rust There is no evidence of pitting. Weld on liner is not coated. Rust with no evidence of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.

Table 3.5.5-2, Containment Visual Inspection (IWE)			
Component ID / Report No.	**Indication Description**	**Disposition**	**Comments**
	Uncoated surface area approx. 3'0" x 1'0". Has light rust with no evidence of pitting. Coating appears to have been removed by mech. means. Beam attachments are not accessible for visual inspection. This applies only to bottom section.		
Liner 93-3 ISI-VT-16-062	Uncoated surface on weld seams. Light corrosion with no evidence of pitting. Uncoated surface with light corrosion. No evidence of pitting. Uncoated surfaces with light to medium rust. This is mainly around the welded connections and surrounding area in the water box. There is no evidence of pitting. Uncoated surfaces with light to medium rust (3 areas). There is no evidence of pitting. Uncoated surface with light corrosion on embed plate. No evidence of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.
Liner 93-4 ISI-VT-16-063	Coatings removed in this area. This area is where suppression pool instrument cable was attached to liner. There are areas of light rust that have no evidence of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.
Liner 93-5 ISI-VT-16-064	Coatings removed in this area. This area is where suppression pool instrument cable was attached to liner. There are areas of light rust that have no evidence of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.
Liner 93-6 ISI-VT-16-065	Coating removed at welds. Welds have light rust. Coatings removed in these areas. Zinc is in place.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.

Table 3.5.5-2, Containment Visual Inspection (IWE)

Component ID / Report No.	Indication Description	Disposition	Comments
	Coatings removed in this area. This area is where suppression pool instrument cable was attached to liner. Areas have light rust. There is no evidence of pitting.		
Liner 93-8 ISI-VT-16-067	Uncoated surface on liner weld. Light rust with no evidence of pitting. Uncoated surface. End of weld has light corrosion with no evidence of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.
Liner 120-1 ISI-VT-16-018	Uncoated surface with light rust. There is no evidence of pitting. Uncoated surface on top half of penetration. Zinc coating is intact. There is no evidence of pitting. Uncoated surface where suppression pool instruments are installed. Light to medium rust in some areas with no evidence of pitting. Uncoated surface with light rust. No evidence of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.
Liner 120-2 ISI-VT-16-019	Uncoated surface. Zinc still in place. Surface is 1½" approx. Uncoated surface. Welds have minor rust. No evidence of pitting. Visible rust streaks. The source is inaccessible for inspection. Uncoated surface. Light rust at weld on embed plate. No evidence of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.

Table 3.5.5-2, Containment Visual Inspection (IWE)

Component ID / Report No.	Indication Description	Disposition	Comments
Liner 120-3 ISI-VT-16-020	Uncoated surface with no rust. Area is approx. 1/8" x ½". Uncoated surface with no rust. Area is approx. ½" x ½". Uncoated surface with no rust. Area is approx. 1½" x ½". There is no indication of pitting on items shown above.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.
Liner 120-4 ISI-VT-16-021	Uncoated surface approx. ¼" (chipped paint). Uncoated surface approx. 1½" x ¾" (chipped paint). There is no indication of pitting in removal areas.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.
Liner 120-5 ISI-VT-16-022	Coatings removed in this area. This area is where suppression pool instrument cable was attached to liner. Rust in area. This area is used for storage during refuel outages. There are multiple areas where coatings have been removed (chipped, scratches). Light rust in area. There is no indication of pitting in areas of light rust.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.
Liner 120-6 ISI-VT-16-023	Coatings removed in this area. This area is where suppression pool instrument cable was installed. Light rust in areas. Visible rust streaks. The source is inaccessible for inspection. Coating removed from 3" area. Primer is still intact. There is no indication of pitting in areas of light rust.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.

Table 3.5.5-2, Containment Visual Inspection (IWE)

Component ID / Report No.	Indication Description	Disposition	Comments
Liner 120-7 ISI-VT-16-024	Uncoated surfaces with light and medium rust where suppression pool instrumentation cables are attached to liner. No evidence of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.
Liner 120-8 ISI-VT-16-025	Uncoated surfaces with light and medium rust where suppression pool instrumentation cables are installed. Rust in some areas with no evidence of pitting. Uncoated surface at end cap. Light rust with no evidence of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.
Liner 135-1 ISI-VT-16-026	Uncoated surfaces around removal area on embed plate. There is light rust with no evidence of pitting. Uncoated surface with light rust on penetration cover. There is no evidence of pitting. Uncoated surface with light rust. Areas are approx. 1". There is no evidence of pitting. Uncoated surface with light rust. These are small areas with no evidence of pitting (3 places). Uncoated surface with light rust. Area is approx. 2" with no evidence of pitting. Uncoated surface on weld. There is light to medium rust with no evidence of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.
Liner 135-2 ISI-VT-16-027	Uncoated surface with light to medium rust. This area extends to below the seam weld into the expansion joint at 161'elev. This area is inaccessible for examination. There is no indication of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.

Table 3.5.5-2, Containment Visual Inspection (IWE)

Component ID / Report No.	Indication Description	Disposition	Comments
	Uncoated surface with light rust (2 places). This is no indication of pitting. Uncoated surface with light rust. This is no indication of pitting. Uncoated surface with no rust or pitting. Paint in an area of approx. 4" x 2.5" has peeled. Zinc is still intact. Uncoated surface with no rust or pitting. Paint in an area of approx. 1.5" x 2.5" has peeled. Zinc is still intact. Uncoated surface with light rust. Area is approx. 2" in length. There is no indication of pitting. Uncoated surface with no rust or pitting. There are scattered areas of chipped paint. Zinc is still intact. Uncoated surface on portions of the weld. There is no rust or pitting.		
Liner 135-3 ISI-VT-16-028	Uncoated surface on plate to liner weld. There is light rust with no indication of pitting. Uncoated surface on seam weld. There is light rust with no indication of pitting. Item 3. Uncoated surface with no rust and no pitting. Paint has chipped away in an area of approx. 1" x 2". Zinc coating is still intact. Uncoated surface with no rust or pitting. Paint has flaked away in this area. Zinc coating is still intact.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.

Table 3.5.5-2, Containment Visual Inspection (IWE)

Component ID / Report No.	Indication Description	Disposition	Comments
	Uncoated surface with no rust or pitting. There are numerous areas of chipped paint. Zinc coating is still intact. Uncoated surface with light rust on the weld. There is no indication of pitting. Uncoated surface on embed plate. There is light rust with no indication of pitting. Uncoated surface with light rust. There is no indication of pitting. Uncoated surface on seam weld. There is light rust with no indication of pitting. Uncoated surface on the liner at the expansion joint. This does not extend behind the expansion joint. There is no evidence of pitting. Uncoated surface with no rust or pitting. Paint has flaked away in an area approx. 1" x 1.5".		
Liner 135-4 ISI-VT-16-029	Uncoated surface with light rust. There is no indication of pitting (2 places). Light rust on weld. There is no indication of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.
Liner 135-5 ISI-VT-16-030	Uncoated surface with light rust. There is no evidence of pitting. Uncoated surface with light rust around penetrations. There is no evidence of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.

Table 3.5.5-2, Containment Visual Inspection (IWE)

Component ID / Report No.	Indication Description	Disposition	Comments
	Uncoated surface with medium to light rust (7 places). There is no evidence of pitting. Uncoated surface with light rust. Area is approx. 12" x 2". There is no evidence of pitting. Uncoated surface with light rust. Area is approx. 14" x 2". There is no evidence of pitting. Uncoated surface with light rust. There is no evidence of pitting. Uncoated surface with light rust. Area is approx. 4" x 12". There is no evidence of pitting. Uncoated surface with light rust. Area is approx. 2" diameter. There is no evidence of pitting. Uncoated surface with light rust. Area is approx. 3" diameter. There is no evidence of pitting. Uncoated surface with light rust. There is no evidence of pitting. Uncoated surface with light rust at weld. There is no evidence of pitting.		
Liner 135-6 ISI-VT-16-031	Uncoated surface with light rust behind I-beam (3 places). Uncoated surface with light rust at welds. Uncoated surface with light rust approx. 3" sq.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.

Table 3.5.5-2, Containment Visual Inspection (IWE)

Component ID / Report No.	Indication Description	Disposition	Comments
	Uncoated surface with light rust approx. 10" x 4". Uncoated surface with light rust approx. 4" x 6". Uncoated surface with light rust the full length of the plate. Paint has chipped and or peeled. Bare metal with light rust. Areas are approx. 3" diameter (4 places). Bare metal with light rust approx. 3" diameter. Inaccessible areas behind vertical trays. No evidence of pitting in areas identified as having light rust.		
Liner 135-7 ISI-VT-16-032	Uncoated surface at embed to liner weld. There is light rust with no indication of pitting. Uncoated surface at eye bolt welds. There is light rust with no indication of pitting. Uncoated surface with light rust. There is no indication of pitting. Uncoated surface with light rust. There is no indication of pitting. Uncoated surface with light rust. Area is approx. 24" x 2". There is no indication of pitting. Uncoated surface with light rust. Area is approx. 3" x 4". There is no indication of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.

Table 3.5.5-2, Containment Visual Inspection (IWE)			
Component ID / Report No.	**Indication Description**	**Disposition**	**Comments**
	Uncoated surface with no rust and no pitting. Location is scattered with areas of chipped paint. Zinc is intact. Uncoated surface with light rust on attachment. There is no indication of pitting. There is a gouge approx. 3/4" x 1/4" x 1/32" deep. There is light rust with no indication of pitting. There is a scratch approx. 3/8" x 1/4". There is light rust with no indication of pitting.		
Liner 135-8 ISI-VT-16-033	Uncoated surface with light rust. Area is approx. 3" x 1 ". There is no indication of pitting. Uncoated surface with light rust on weld. There is no indication of pitting. Uncoated surface with light rust. Area is approx. 10" x 4". There is no indication of pitting. Uncoated surface with light rust on penetration covers. There is no indication of pitting. Uncoated surface with light rust on attachment welds (8 places). There is no indication of pitting. Uncoated surface with light rust. There is no indication of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.
Liner 161-1 ISI-VT-16-034	Uncoated surface with light rust on penetration surface. There is no indication of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.

Table 3.5.5-2, Containment Visual Inspection (IWE)

Component ID / Report No.	Indication Description	Disposition	Comments
	Uncoated surface with light rust on attachment welds. There is no indication of pitting. Uncoated surface with light rust on penetration cover and attachment welds. There is no indication of pitting. Uncoated surface with light rust on strain gauge (2 places). There is no indication of pitting. Uncoated surface with light rust (3 places). Area is approx. 2" diameter. There is no indication of pitting. Uncoated surface with light rust. Area is approx. 3 1/2" x 1 1/2". There is no indication of pitting. Uncoated surface with light rust. Area is approx. 4" x 2". There is no indication of pitting. Uncoated surface with light rust. Area is approx. 3" x 2". There is no indication of pitting. Uncoated surface with light rust. Area is approx. 5" x 4". There is no indication of pitting. Uncoated surface with light rust (3 places). There is no indication of pitting. Uncoated surface with light rust (10 places). There is no indication of pitting.		

Table 3.5.5-2, Containment Visual Inspection (IWE)

Component ID / Report No.	Indication Description	Disposition	Comments
	Uncoated surface. There are numerous areas of chipped and peeled paint. There is light rust in some areas with no indication of pitting.		
Liner 161-2 ISI-VT-16-035	Uncoated surface with light rust. Area is approx. 4" x 3" (4 places). There is no indication of pitting. Uncoated surface with light rust on the penetration covers (3 places). There is no indication of pitting. Uncoated surface with light rust. There is no indication of pitting. Discernable bulge with a diameter of 8". This bulge extends outward approx. 1/2". There is no flaking or peeling of coatings in this area. UT thickness measurements were performed in the area on and around the bulge. There is no reduction of base material from that recorded on NDE Report BOP-UT-07-008. Uncoated surface with light rust. Area is approx. 1/2" x 4". There is no indication of pitting. Uncoated surface with light rust or pitting. Paint has been chipped but the zinc coating is intact. Uncoated surface with light rust. Area is approx. 4" diameter. There is no indication of pitting. Uncoated surface with light rust on the seam weld (2 places). There is no indication of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.

Table 3.5.5-2, Containment Visual Inspection (IWE)			
Component ID / Report No.	**Indication Description**	**Disposition**	**Comments**
	Uncoated surface on the sway strut attachment weld. There is no indication of pitting. Paint has flaked in area approx. 1/2" x 2". Zinc coating is intact.		
Liner 161-3 ISI-VT-16-036	Uncoated surface at T.S. attachment welds. There is light rust with no indication of pitting. Uncoated surface with light rust on penetration cover. There is no indication of pitting. Uncoated surface with light rust on penetration cover and pipe. There is no indication of pitting. Uncoated surface with light rust. There is no indication of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.
Liner 161-4 ISI-VT-16-037	Uncoated surface with light rust and no pitting on penetration covers (5 pieces). Uncoated surface with light rust and no pitting on the attachment weld. Uncoated surface with light rust and no pitting on the gauge mount. Uncoated surface with light rust. No indication of pitting. Uncoated surface with light rust and no pitting on removal areas (3 places). Uncoated surface with light rust and no pitting at seam weld. Area is approx. 6" in length.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.

Table 3.5.5-2, Containment Visual Inspection (IWE)			
Component ID / Report No.	**Indication Description**	**Disposition**	**Comments**
Liner 161-5 ISI-VT-16-038	Uncoated surface with light rust where unistrut attaches to the plate (6 places). No indication of pitting. Uncoated surface with light rust. Area is approx. 10" x 4" (3 places). There is no indication of pitting. Uncoated surface with light rust. Area is approx. 6" x 4" (2 places). There is no indication of pitting. Uncoated surface with light rust on the penetration cover and pipe (2 places). There is no indication of pitting. Uncoated surface at the strain gauge weld attachments (6 places). There is no indication of pitting. Uncoated surface with light rust. No indication of pitting. Uncoated surface with light rust at the attachment weld. No indication of pitting. Uncoated surface with light rust. Area is approx. 7" x 3" (2 pieces). No indication of pitting. Uncoated surfaces approx. 6" x 3" (2 places). There is light rust with no indication of pitting. Uncoated surfaces approx. 6" x 4" (2 places). There is light rust with no indication of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.
Liner 161-6 ISI-VT-16-039	Uncoated surface on attachment weld at strain gauges (4 places). There is light rust with no indication of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.

Table 3.5.5-2, Containment Visual Inspection (IWE)

Component ID / Report No.	Indication Description	Disposition	Comments
	Uncoated surface with light rust. Area is approx. 14" x 8". There is no indication of pitting. Uncoated surface with light rust. There is no indication of pitting. Uncoated surface with four areas with arc strikes. No indication of cracking or pitting. Uncoated surface 360° around the equipment hatch flange. Light rust with no indication of pitting. Uncoated surface with light rust. Area is approx. 18" x 6". There is no indication of pitting.		
Liner 161-7 ISI-VT-16-040	Uncoated surface on pipe behind penetration cover (2 places). There is light rust with no indication of pitting. Uncoated surface on attachment weld at strain gauge. There is light rust with no indication of pitting. Uncoated surface on attachment weld. There is light rust with no indication of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.
Liner 161-8 ISI-VT-16-041	Uncoated surface at strain gauge weld attachment. There is light rust with no indication of pitting. Scattered areas of chipped paint. No rust. Zinc coating is intact. Angle removal area with light rust. No indication of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.
Liner 184-1 ISI-VT-16-042	Uncoated surface with light rust (3 places). There is no indication of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.

Table 3.5.5-2, Containment Visual Inspection (IWE)			
Component ID / Report No.	**Indication Description**	**Disposition**	**Comments**
	Uncoated surface with strain gauge. There is medium rust with no indication of pitting. Uncoated surface at attachment weld. There is light rust with no indication of pitting. Uncoated surface with light rust (4 places). There is no indication of pitting. Uncoated surface with light rust (7 places). There is no indication of pitting. Uncoated surface with no rust. Area is an ark strike with no indication of cracks or pitting. Uncoated surface with light rust. There is no indication of pitting. Gouge with a reduction of 0.060" from nominal wall. Nominal wall is 0.275 ". Reduction was caused from grinding. Location of gouge is at 194' EL. Gouge with a reduction of 0.046" from nominal wall. Nominal wall is 0.268 ". Reduction was caused from lug removal at location 186'-5" EL. Gouge with a reduction of 0.0625" from nominal wall. Nominal wall is 0.268". Reduction was caused from lug removal at location 187'-5" EL.		
Liner 184-2 ISI-VT-16-043	Uncoated surface with light rust. There is no indication of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.

Table 3.5.5-2, Containment Visual Inspection (IWE)			
Component ID / Report No.	**Indication Description**	**Disposition**	**Comments**
	Uncoated surface with light rust (10 places). There is no indication of pitting. Uncoated surface with light rust. Area is approx. 4" x 2". Uncoated surface with no rust or pitting. There are numerous areas of chipped paint. Zinc coating is intact.		
Liner 184-3 ISI-VT-16-044	Gouge with reduction of 0.078" from nominal wall. Nominal wall is 0.282". Area is approx. 1/2" diameter. Location of gouge is 189'-10 " at AZ-117°. Uncoated surface with chipped paint in numerous areas. There is no rust and the zinc coating is intact. Uncoated surface with light rust. There is no indication of pitting. Uncoated surface due to arc strikes (5 places). There is no indication of pitting. Uncoated surface with light rust. Area approx. 1" diameter. There is no indication of pitting. Uncoated surface with medium rust (3 places). There is no indication of pitting. Uncoated surface with light rust. Area is approx. 2" diameter. There is no indication of pitting. Uncoated surface with light rust (5 places). There is no indication of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.

Table 3.5.5-2, Containment Visual Inspection (IWE)

Component ID / Report No.	Indication Description	Disposition	Comments
	Uncoated surface with medium rust in an area approx. 12" square. There is no indication of pitting. Uncoated surface with light rust in an area approx. 1" diameter. There is no indication of pitting. Uncoated surface with light rust (3 places). There is no indication of pitting.		
Liner 184-4 ISI-VT-16-047	Uncoated surface at attachment with light rust (2 places). There is no indication of pitting. Uncoated surface at penetration weld. There is light rust with no indication of pitting. Uncoated surface with light rust on penetration (2 places). There is no indication of pitting. Uncoated surface with light rust. Area is approx. 8" x 5". There is no indication of pitting. Uncoated surface with light rust. Area is approx. 12" x 5", There is no indication of pitting. Uncoated surface with light rust. Area is approx. 2" diameter (3 places). There is no indication of pitting. Uncoated surface with light rust at strain gauge. There is no indication of pitting. Uncoated surface with light rust. Area is approx. 12" x 10". There is no indication of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.

Table 3.5.5-2, Containment Visual Inspection (IWE)

Component ID / Report No.	Indication Description	Disposition	Comments
	Uncoated surface with light rust. Area is approx. 12" x 10". There is no indication of pitting. Uncoated surface with light rust. Area is approx. 14" x 18". There is no indication of pitting.		
Liner 184-5 ISI-VT-16-049	Uncoated surface with light rust. Area is approx. 12" x 4". There is no indication of pitting. Uncoated surface with light rust. Area is approx. 12" x 6". There is no indication of pitting. Uncoated surface with light rust (9 places). There is no indication of pitting. Uncoated surface on embed plate with medium rust. There is no indication of pitting. Uncoated surface on embed plate with medium rust. There is no indication of pitting. Uncoated surface with light rust (2 places). Area is approx. 12" x 8". There is no indication of pitting. Uncoated surface with light rust. Area is approx. 12" x 8". There is no indication of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.
Liner 184-6 ISI-VT-16-049	Uncoated surface with light rust and unistrut attachment (2 places). There is no indication of pitting. Uncoated surface with light rust at strain gauge (2 places). There is no indication of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.

Table 3.5.5-2, Containment Visual Inspection (IWE)

Component ID / Report No.	Indication Description	Disposition	Comments
	Uncoated surface with light rust at attachment weld. There is no indication of pitting. Uncoated surface with light rust. Area is approx. 3" diameter. There is no indication of pitting. Uncoated surface with light rust. Area is approx. 4" diameter. There is no indication of pitting. Uncoated surface with medium rust at strain gauge. There is no indication of pitting.		
Liner 184-7 ISI-VT-16-050	Uncoated surface with light rust at attachment weld. There is no indication of pitting. Uncoated surface with light rust. Area is approx. 2" diameter. There is no indication of pitting. Uncoated surface with light rust. Area is approx. 1/2" diameter. There is no indication of pitting. Uncoated surface with light rust. Area is approx. 1 1/2" x 1 ". There is no indication of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.
Liner 184-8 ISI-VT-16-051	Uncoated surface with light rust at attachment weld (2 places). There is no indication of pitting. Uncoated surface with light rust (6 places). There is no indication of pitting. Uncoated surface with light rust. Area is approx. 2" diameter. There is no indication of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.

Table 3.5.5-2, Containment Visual Inspection (IWE)

Component ID / Report No.	Indication Description	Disposition	Comments
	Uncoated surface with light rust. Area is approx. 8" x 6". There is no indication of pitting. Uncoated surface with light rust. Area is approx. 12" x 12". There is no indication of pitting. Uncoated surface with light rust. Area is approx. 3" x 2". There is no indication of pitting. Uncoated surface with light rust. Area is approx. 6" x 4". There is no indication of pitting. Uncoated surface with light rust. Area is approx. 6" x 2". There is no indication of pitting. Uncoated surface with light rust (2 places). There is no indication of pitting. Uncoated surface with light rust (2 places). There is no indication of pitting.		
Liner 208-1 ISI-VT-16-052	Uncoated surface with light rust. Where structural steel welds to embed plate. There is no indication of pitting. Uncoated surface with light rust. Area is approx. 1/12" x 1/2". There is no indication of pitting. Uncoated surface with no rust or pitting. Numerous areas of chipped paint. Zinc is intact. Comments: There are a few previously identified gouges in the lower liner plate. In 8/2003 a UT was performed to verify the thickness of the liner plate. The average thickness of the liner plate in this area is .297". Gouges do not exceed .037".	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.

Table 3.5.5-2, Containment Visual Inspection (IWE)

Component ID / Report No.	**Indication Description**	**Disposition**	**Comments**
Liner 208-2 ISI-VT-16-053	Uncoated surface with light rust where structural steel welds to embed plate. There is no indication of pitting. Uncoated surface with light rust. Area is approx. 1 1/2" x 1/2". There is no indication of pitting. Uncoated surface with no rust or pitting. Numerous areas of chipped paint. Zinc is intact. Uncoated surface with light rust (2 places 4" x 8"). There is no indication of pitting. Comments: There are a few previously identified gouges in the lower liner plate. In 08/2003 a UT was performed to verify the thickness of the liner plate. The average thickness of the liner plate in this area is .297". Gouges do not exceed 0.37".	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.
Liner 208-3 ISI-VT-16-054	Uncoated surface with light rust. Area is approx. 1" diameter. There is no indication of pitting. Uncoated surface with light rust. Area is approx. 2" x 6". There is no indication of pitting. Uncoated surface with medium rust at unistrut weld. There is no indication of pitting. Uncoated surface with light rust. There is no indication of pitting. Uncoated surface with light rust on seam weld. Area is approx. 1" long. There is no indication of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.

Table 3.5.5-2, Containment Visual Inspection (IWE)

Component ID / Report No.	Indication Description	Disposition	Comments
	Uncoated surface with no rust or pitting. Zinc is intact. Uncoated surface with light rust. Small areas of chipped paint. There is no indication of pitting. Uncoated surface with no rust or pitting. Zinc is intact. Uncoated surface with no rust or pitting. Numerous areas of chipped paint. Zinc is intact. Uncoated surface repaired area. There is no indication of rust. Comments: There a few previously identified gouges in the lower liner plate. The average thickness of the liner plate in this area is .297". Gouges do not exceed 0.37"		
Liner 208-4 ISI-VT-16-055	Uncoated surface with medium rust where structural steel welds to embed plate (2 places). There is no indication of pitting. Uncoated surface with light rust where structural steel weld to embed. There is no indication of pitting. Uncoated surface with no rust or pitting. Numerous areas of chipped paint. Zinc is intact. Comments: There are a few previously identified gouges in the lower liner plate. On 08/2003 a UT was performed to verify the thickness of the liner plate. The average thickness of the liner plate in this area is .297". Gouges do not exceed 0.37".	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.

Table 3.5.5-2, Containment Visual Inspection (IWE)

Component ID / Report No.	**Indication Description**	**Disposition**	**Comments**
Liner 208-5 ISI-VT-16-056	Uncoated surface with light rust at strain gauge (2 places). There is no indication of pitting. Uncoated surface with light rust on embed plate (2 places). There is no indication of pitting. Uncoated surface with no rust or pitting. Uncoated surface with no rust or pitting. There are numerous areas of chipped paint. Uncoated surface behind T.S. There is no rust or pitting. Uncoated surface with bare metal (1 place - 1 1/2" x 3") with no rust or pitting. Uncoated surface (bare metal) with no rust or pitting behind pipe support.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.
Liner 208-6 ISI-VT-16-057	Uncoated surface with light rust on embed plate. Area is approx. 3" x 1 ". There is no indication of pitting. Uncoated surface with light rust at T.S. to embed welds. There is no indication of pitting. Uncoated surface with light rust. Coating is cracked and peeling. There is no indication of pitting. Uncoated surface where paint is flaking and peeling. There is no pitting. Zinc is intact. Uncoated surface where paint is peeling. There is no rust or pitting. Zinc is intact.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.

Table 3.5.5-2, Containment Visual Inspection (IWE)

Component ID / Report No.	Indication Description	Disposition	Comments
Liner 208-7 ISI-VT-16-058	Uncoated surface with medium rust on embed plate weld to liner. Area is approx. 12" long. There is no indication of pitting. Uncoated surface with light rust. Area is approx. 1" x 1/2". There is no indication of pitting. Uncoated surface with light rust where structural steel welds to embed. There is no indication of pitting. Uncoated surface with light rust. Area is approx. 1" diameter. There is no indication of pitting. Uncoated surface with no rust or pitting. Numerous areas have chipped paint. Zinc coating is intact. Uncoated surface with no rust or pitting. Numerous areas have chipped paint. Zinc coating is intact. Uncoated surface (1/2" x 12") with no rust or pitting. Zinc coating is intact.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.
Liner 208-8 ISI-VT-16-059	Uncoated surface with light rust where T.S. is welded to embed. There is no indication of pitting. Uncoated surface with light rust where structural steel welds to embed. There is no indication of pitting. Uncoated surface with light rust where structural steel welds to embed. There is no indication of pitting. Uncoated surface with light rust on embed plate. There is no indication of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.

Table 3.5.5-2, Containment Visual Inspection (IWE)

Component ID / Report No.	Indication Description	Disposition	Comments
	Uncoated surface with light rust (5 places). There is no indication of pitting. Uncoated surface with light rust (2 places). Areas are approx. 5" x 9". There is no indication of pitting. Uncoated surface with no rust or pitting. There are numerous areas where paint has peeled or chipped. Zinc in intact.		
Containment Dome Liner			
Liner D-3 ISI-VT-15-005	Uncoated surface with light rust on seam weld. Area is approx. 1 O" long. There is no indication of pitting. Uncoated surface with light rust Area is approx. 3" diameter. There is no indication of pitting. Uncoated surface with light rust Area is approx. 6'9 x 4". There is no indication of pitting. Uncoated surface with light rust Area is approx. 4" x 12". There is no indication of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.
Liner D-4 ISI-VT-15-002	Uncoated surface with light rust Area is approx. 2" diameter (2 places). There is no evidence of pitting. Uncoated surface with light rust Area is approx.1 1/2" diameter (2 places). There is no evidence of pitting. Uncoated surface with light rust Area is approx.12" x 3". There is no evidence of pitting. Uncoated surface with light rust Area is approx. 4" x 12". There is no evidence of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.

Table 3.5.5-2, Containment Visual Inspection (IWE)

Component ID / Report No.	Indication Description	Disposition	Comments
	Uncoated surface with light rust Area is approx. 2" diameter. There is no evidence of pitting. Uncoated surface with light rust. Area is approx. 6" x 4". There is no evidence of pitting.		
Liner D-1 ISI-VT-15-003	Uncoated surface with light rust. Area is approx. 2" diameter (2 places). There is no indication of pitting. Uncoated surface with medium rust Area is approx. 4" x 1" diameter. There is no indication of pitting. Uncoated surface with light rust. Area is approx. 3" diameter. There is no indication of pitting. Uncoated surface with medium rust Area is approx. 6" x 1" diameter. There is no indication of pitting. Uncoated surface with medium rust Area is approx. 1" diameter. There is no indication of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.
Liner D-2 ISI-VT-15-004	Uncoated surface with light rust at plate to stiffener to embed plate. There is no evidence of pitting. Uncoated surface with light rust at clevis to liner weld. Area is approx. 6" x 6" diameter. There is no evidence of pitting. Uncoated surface with light rust. Area is approx. 1 1/2" x 3/4". There is no indication of pitting. Uncoated surface with light rust. Area is approx. 2" diameter. There is no indication of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.

Table 3.5.5-2, Containment Visual Inspection (IWE)

Component ID / Report No.	**Indication Description**	**Disposition**	**Comments**
Lower Personnel Airlock			
SA-119 AL ISI-VT-16-068	Uncoated surface with light rust. Area around angles are not painted. There is no indication of pitting. (4 places) Uncoated surface with light rust. There are numerous areas of chipped paint. There is no indication of pitting. Uncoated surface with light rust. Instrument tubing brackets are not painted. There is no indication of pitting. Uncoated surface with light rust. Paint removed from wear. There is no indication of pitting. Uncoated surface with light rust. There are several areas of chipped paint. There is no indication of pitting. Uncoated surface with light rust on flange. There is no indication of pitting. Uncoated surface with light rust. Paint in these areas are chipped with no indication of pitting. Uncoated surface with light rust on side of the door. There is no indication of pitting. Uncoated surface (1 " x 4") with light rust. There is no indication of pitting. Uncoated surface with light rust on seal clamp, there is no indication of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.

Table 3.5.5-2, Containment Visual Inspection (IWE)

Component ID / Report No.	Indication Description	Disposition	Comments
	Uncoated surface with light rust. Area is approx. 6" x 6". There is no indication of pitting. Uncoated surface with light rust on unistrut plate. There is no indication of pitting. Uncoated surface with rust at T.S. weld. There is no indication of pitting. Uncoated surface with light rust on seal clamp. There is no indication of pitting. Uncoated surface with light rust on seal clamp. There is no indication of pitting. Uncoated surface with light rust on unistrut bracket. There is no indication of pitting. Uncoated surface with light rust on instrument tubing bracket. There is no indication of pitting. Uncoated surface with light rust on seal clamp. There is no indication of pitting.		
Upper Personnel Airlock			
SA-212 AL ISI-VT-16-069	Uncoated surface with light rust on angle clips. There is no indication of pitting. (4 places) Uncoated surface with light rust on the left side facing containment. There is no indication of pitting. Uncoated surface with light rust on instrument tubing brackets. There is no indication of pitting.	Items were previously identified and evaluated acceptable.	No additional degradation noted during this examination.

Table 3.5.5-2, Containment Visual Inspection (IWE)

Component ID / Report No.	Indication Description	Disposition	Comments
	Item 3. Uncoated surface with light rust. Paint removed from wear. There is no indication of pitting. Uncoated surface with light rust on seal clamp. There is no indication of pitting. Uncoated surface with light rust on instrument bracket. There is no indication of pitting. Uncoated surface with light rust on T.S. weld. There is no indication of pitting. Uncoated surface with light rust. Area is approx. 5' x 5'. There is no indication of pitting. Uncoated surface with light rust on seal clamp. There is no indication of pitting. Uncoated surface. Paint removed from wear. There is no rust of pitting. Uncoated surface with light rust on seal clamp. There is no indication of pitting. Uncoated surface due to chipped paint. There is numerous areas. There is no rust or pitting. Uncoated surface with light to medium rust. There is no indication of pitting. Uncoated surface with light rust on seal clamp. There is no indication of pitting.		

Table 3.5.5-3, Containment Visual Inspection (IWL)			
Component ID / Report No.	**Indication Description**	**Disposition**	**Comments**
RF20, March 2016			
WS-1 ISI-VT-16-076	1 ¾" x 1 ¾" x ¼" deep indication. Staining above penetrations.	Indications were previously identified and evaluated. No changes.	Accepted by examination.
WS-2 ISI-VT-16-104	Surface cracks, .005" or less.	Indications were previously identified and evaluated. No changes.	Accepted by examination.
WS-3 ISI-VT-16-077	Rust stains noted from grating above, present in 2006 as well.	Indications were previously identified and evaluated. No changes.	Accepted by examination.
WS-5 ISI-VT-16-078	8" x 2" x .5" deep indication at elevation 110'.	Indications were previously identified and evaluated. No changes.	Accepted by examination.
WS-7 ISI-VT-16-080	Construction damage, .5" x 1" x .375" deep. Construction damage, .5" x 1.5" x .250" deep. Staining from floor above, not structural.	Indications were previously identified and evaluated. No changes.	Accepted by examination.
WS-8 ISI-VT-16-081	Surface cracks, .005" and .004". Light rust staining at penetration 19.	Indications were previously identified and evaluated. No changes.	Accepted by examination.
WS-9 ISI-VT-16-082	Construction damage, 2" x 4" x .5" deep indication.	Indications were previously identified and evaluated. No changes.	Accepted by examination.
WS-11 ISI-VT-16-084	Fine surface crack, no growth of rust. Construction void, 2.5" x 4.5" x .375".	Indications were previously identified and evaluated. No changes.	Accepted by examination.

Table 3.5.5-3, Containment Visual Inspection (IWL)

Component ID / Report No.	Indication Description	Disposition	Comments
WS-12 ISI-VT-16-085	Voids: Few voids were noticed in this area. They are all very local in nature and the maximum size of the voids noticed is 3" x 1 1/2" x 3/8" deep.	Indications were previously identified and evaluated. No changes.	The voids have no significant impact on the structural integrity or functional capability of the containment.
WS-14 ISI-VT-16-087	Rust staining below penetration 38.	Indications were previously identified and evaluated. No changes.	Accepted by examination.
WS-16 ISI-VT-16-106	Light rust stain.	Indications were previously identified and evaluated. No changes.	Accepted by examination.
WS-17 ISI-VT-16-089	Penetration 62, rust with no pitting. Light staining.	Indications were previously identified and evaluated. No changes.	Accepted by examination.
WS-18 ISI-VT-16-090	Light staining. Penetrations unpainted, light rust with no pitting.	Indications were previously identified and evaluated. No changes.	Accepted by examination.
WS-19 ISI-VT-16-091	Light stains from floor above.	Indications were previously identified and evaluated. No changes.	Accepted by examination.
WS-20 ISI-VT-16-092	Light rust staining.	Indications were previously identified and evaluated. No changes.	Accepted by examination.
WS-21 ISI-VT-16-093	Light rust stains from floor above.	Indications were previously identified and evaluated. No changes.	Accepted by examination.
WS-22 ISI-VT-16-094	Light staining. Area of moderate to heavy staining around penetrations 210, 108, 205, 211, 63.	Indications were previously identified and evaluated. No changes.	Accepted by examination.
WS-23 ISI-VT-16-095	Minor chipping from construction at penetration 61.	Indications were previously identified and evaluated. No changes.	Accepted by examination.
WS-24 ISI-VT-16-096	Light rust staining. Previously identified voided areas have been repaired and painted.	Indications were previously identified and evaluated. Repaired and painted.	Accepted by examination.

Table 3.5.5-3, Containment Visual Inspection (IWL)

Component ID / Report No.	Indication Description	Disposition	Comments
WS-25 ISI-VT-16-097	Light rust stains.	Indications were previously identified and evaluated. No changes.	Accepted by examination.
WS-26 ISI-VT-16-098	Rust stains from floor above.	Indications were previously identified and evaluated. No changes.	Accepted by examination.
WS-27 ISI-VT-16-107	Surface cracking (typical)	Indications were previously identified and evaluated. No changes.	Accepted by examination.
WS-28 ISI-VT-16-099	Surface cracking (typical). All surface cracks less than .005".	Indications were previously identified and evaluated. No changes.	Accepted by examination.
WS-29 ISI-VT-16-108	Seam area rough from construction. Form rod exposed. 3" x 3" x 4" void, form rod exposed. 3/8" x 1" x 3/4" void with form rod exposed. 3/4" x 3/8" x 3/4" void. 3" x 3" x 4" void with form rod exposed.	Indications were previously identified and evaluated. No changes.	Accepted by examination.
WS-30 ISI-VT-16-100	Void, 3" diameter, 1/2" deep. Efflorescence (EFF), 6'. EFF, 10". Voids, 3 at 3" x 1/2" deep. Form rod from construction. Voids, 3 at 3" x 3".	Indications were previously identified and evaluated. No changes.	Accepted by examination.
WS-31 ISI-VT-16-109	Void, 6" x 5" x 3/8 – 1/4 variable.	Indications were previously identified and evaluated. No changes.	Accepted by examination.
WS-32 ISI-VT-16-101	Construction voids along construction joint. EFF, 6'. Form rod with void 2" x 1" deep. Void with form rod 3" deep.	Indications were previously identified and evaluated. No changes.	Accepted by examination.

Table 3.5.5-3, Containment Visual Inspection (IWL)			
Component ID / Report No.	**Indication Description**	**Disposition**	**Comments**
RF-18, April 2012			
WS-1 ISI-VT-12-042	1 ¾" x 1 ¾" x ¼" deep indication. Staining above penetrations.	Previously identified indications still exist – unchanged.	Accepted by examination.
WS-2 ISI-VT-12-075	Surface cracks, .005" or less.	Indications previously identified and evaluated.	Accepted by examination.
WS-3 ISI-VT-12-043	Minor rust stains from grating above.	Previously identified indications still exist – unchanged.	Accepted by examination.
WS-5 ISI-VT-12-044	8" x 2" x .5" deep indication at elevation 110'.	Previously identified indications still exist – unchanged.	Accepted by examination.
WS-7 ISI-VT-12-072	Construction damage, .5" x 1" x .375" deep. Construction damage, .5" x 1.5" x .250" deep. Staining from floor above, not structural.	Indications were previously identified and evaluated. No changes.	Accepted by examination.
WS-8 ISI-VT-12-046	Surface cracks, .005" and .004". Light rust staining at penetration 19.	Surface cracks as noted on WS-08. Light rust stains noted on WS-08.	Accepted by examination.
WS-9 ISI-VT-12-057	Construction damage.	Previously identified indications still exist – unchanged.	Accepted by examination.
WS-11 ISI-VT-12-047	Fine surface crack, no growth of rust. 2.5" x 4.5" x .375" construction void.	Previously identified indications still exist – unchanged.	Accepted by examination.
WS-12 ISI-VT-12-048	Voids: Few voids were noticed in this area. They are all very local in nature and the maximum size of the voids noticed is 3" x 1 1/2" x 3/8" deep.	Previously identified indications still exist – unchanged.	Accepted by examination.
WS-14 ISI-VT-12-050	Rust staining below penetration 38.	Previously identified indications still exist – unchanged.	Accepted by examination.

Table 3.5.5-3, Containment Visual Inspection (IWL)			
Component ID / Report No.	**Indication Description**	**Disposition**	**Comments**
WS-16 ISI-VT-12-052	Light rust stain.	Previously identified indications still exist – unchanged.	Accepted by examination.
WS-17 ISI-VT-12-074	Penetration 62, rust with no pitting. Light staining.	Indications were previously identified and evaluated. No changes.	Accepted by examination.
WS-18 ISI-VT-12-069	Light staining. Penetrations unpainted, light rust with no pitting.	Indications were previously reported and are unchanged.	Accepted by examination.
WS-19 ISI-VT-12-055	Light stains from floor above.	Staining indications recorded previously remain, unchanged.	Accepted by examination.
WS-20 ISI-VT-12-056	Light rust staining.	Staining indications recorded previously remain, unchanged.	Accepted by examination.
WS-21 ISI-VT-12-059	Light rust stains from floor above.	Indications previously recorded remain unchanged.	Accepted by examination.
WS-22 ISI-VT-12-060	Light staining. Area of moderate to heavy staining around penetrations 210, 108, 205, 211, 63.	Staining previously recorded remains unchanged.	Accepted by examination.
WS-23 ISI-VT-12-070	Minor chipping from construction at penetration 61.	Minor chips around penetration from construction.	Accepted by examination.
WS-24 ISI-VT-12-062	Light rust staining.	Indications were previously reported and are unchanged.	Accepted by examination.
WS-25 ISI-VT-12-062	Light rust stains.	Indications were previously reported and are unchanged.	Accepted by examination.
WS-26 ISI-VT-12-064	Rust stains from floor above.	Indications were previously reported and are unchanged.	Accepted by examination.
WS-27 ISI-VT-12-053	Surface cracking (typical). Indications range from .005" - .010".	Indications were previously reported as "surface cracking (typical)".	Accepted by examination.
WS-28 ISI-VT-12-054	Surface cracking (typical). Indications range from .005" - .010".	Indications were previously reported as "surface cracking (typical)".	Accepted by examination.

Table 3.5.5-3, Containment Visual Inspection (IWL)

Component ID / Report No.	Indication Description	Disposition	Comments
WS-29 ISI-VT-12-088	Seam area rough from construction. Form rod exposed. 3" x 3" x 4" void, form rod exposed. 3/8" x 1" x 3/4" void with form rod exposed. 3/4" x 3/8" x 3/4" void. 3" x 3" x 4" void with form rod exposed.	Indications were previously identified and evaluated. No changes.	Accepted by examination.
WS-30 ISI-VT-12-081	Void, 3" diameter, 1/2" deep. EFF, 6'. EFF, 10". Voids, 3 at 3" x 1/2" deep. Form rod from construction. Voids, 3 at 3" x 3".	Indications were previously identified and evaluated. No changes.	Accepted by examination.
WS-31 ISI-VT-12-085	Void, 6" x 5" x 3/8 – 1/4" variable.	Indications were previously identified and evaluated. No changes.	Accepted by examination.
WS-32 ISI-VT-12-080	Voids along construction joint. EFF, 6'. Form rod with void 1" deep. Void with form rod 2 1/2" x 3" deep.	Indications were previously identified and evaluated. No changes.	Accepted by examination.

3.6 NRC Notices

3.6.1 Information Notice (IN) 92-20, Inadequate Local Leak Rate Testing

NRC IN 92-20 was issued to alert licensees to problems with local leak rate testing of two-ply stainless steel bellows used on piping penetrations at some plants. Specifically, local leak rate testing could not be relied upon to accurately measure the leakage rate that would occur under accident conditions since, during testing, the two plies in the bellows were in contact with each other, restricting the flow of the test medium to the crack locations. Any two-ply bellows of similar construction may be susceptible to this problem. GGNS has only one bellows that may be subject to the failure mechanism described in this IN. This is the expansion bellows (1G41G515) associated with the horizontal fuel transfer tube (Containment Penetration No. 4). GGNS conducted several tests to verify the adequacy of the local leak rate testing for this bellows and determined the following:

- The bellows have been tested locally every refueling outage until the bellows were placed on an extended test frequency (currently 5 years). The acceptance criteria are very low for this penetration (50 sccm) and the tests have always demonstrated zero leakage.

- During refueling outage 5 (1992), a visual inspection of the exterior surface of the bellows was done while under LLRT test pressure of 11.5 psig. No indications were found of cracks or gouges and the bellows were described as being in good condition.

- Tests were done to verify that air could pass through each of the bellows halves from one test connection to the other and that there were no obstructions to the flow.

- During refueling outage 6 (1993), tests were done to confirm that the bellows' annulus was vented to the containment atmosphere. This ensured that the annulus was being subjected to ILRT test pressure (about 12 psig). This was the fourth ILRT with all results being well below the acceptance limits. In addition, a visual inspection using liquid leak detection fluid was done of the exterior of the bellows while attempting to pressurize the bellows with air.

This testing provides a high degree of confidence that the test methods currently being used are adequate to detect leakage across the bellows assembly. It is also worthwhile to note that the bellows are not subjected to large or rapid temperature changes or other operationally induced stresses.

3.6.2 IN 2010-12, Containment Liner Corrosion

The NRC issued this IN to inform addressees of issues concerning the degradation of the containment liner that could affect the leak-tightness of the containment structure.

IN 2010-12 described the degradation as follows:

Concrete reactor containments are typically lined with a carbon steel liner to ensure a high degree of leak tightness during operating and accident conditions. Operating experience shows that containment liner corrosion is often the result of liner plates being in contact with objects and materials that are lodged between or embedded in the containment concrete. Liner locations that are in contact with objects made of an organic material are susceptible to accelerated corrosion

because organic materials can trap water that combined with oxygen will promote carbon steel corrosion. Organic materials can also cause a localized low pH area when they decompose. Organic materials located inside containment may come in contact with the containment liner and cause accelerated corrosion. However, corrosion that originates between the liner plate and concrete is a greater concern because visual examinations typically identify the corrosion only after it has significantly degraded the liner.

Based on the Operating Experience (OE) evaluation, GGNS is susceptible to the corrosion on the liner plates but GGNS currently has barriers in place to minimize the likelihood of this event. GGNS currently performs liner exams every inspection period and concrete exams every 5 years.

3.6.3 IN 2014-07, "Degradation of Leak Chase Channel Systems for Floor Welds of Metal Containment Shell and Concrete Containment Metallic Liner"

The NRC issued this IN to inform addressees of issues concerning degradation of floor weld leak-chase channel systems of steel containment shell and concrete containment metallic liner that could affect leak-tightness and aging management of containment structures.

IN 2014-07 described the leak chase channel system as follows:

> Consists of steel channel sections that are fillet welded continuously over the entire bottom shell or liner seam welds and subdivided into zones, each zone with a test connection. Each test connection consists of a small carbon or stainless steel tube (less than 1-inch (2.5 centimeters) diameter) that penetrates through the back of the channel and is seal-welded to the channel steel. The tube extends up through the concrete floor slab to a small steel access (junction) box embedded in the floor slab. The steel tube, which may be encased in a pipe, projects up through the bottom of the access box with a threaded coupling connection welded to the top of the tube, allowing for pressurization of the leak-chase channel.

IN 2014-07 describes OE that is concerned about the omission of Code-required exams that were masked by other components and were therefore not included in the IWE database. GGNS is not at risk as the leak chase system of the containment is included in the Containment Inservice Inspection (CISI) program. No new actions were required to address this IN.

3.6.4 Regulatory Issue Summary (RIS) 2016-07, Containment Shell or Liner Moisture Barrier Inspection

The NRC issued this RIS to reiterate the NRC staff’s position regarding ISI requirements for moisture barrier materials, as discussed in the ASME Boiler and Pressure Vessel Code, Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," Subsection IWE.

ASME Code, Section XI, Item E1.11, in Table IWE-2500-1 (E-A), requires general visual examination of 100 percent of accessible surface areas during each inspection period, while Item E1.30 in the same table requires general visual examination of 100 percent of accessible moisture barriers during each inspection period. Note 4 (Note 3 in editions before 2013) for Item E1.30 under the "Parts Examined" column states, "Examination shall include moisture barrier materials intended to prevent intrusion of moisture against inaccessible areas of the pressure retaining metal containment shell or liner at concrete-to-metal interfaces and at metal-to-metal interfaces which are not seal-welded. Containment moisture barrier materials include caulking, flashing, and other sealants used for this application."

GGNS does not have a moisture barrier. GGNS is not at risk as the leak chase system of the containment is included in the Containment Inservice Inspection (CISI) Program. No new actions were required to address this RIS.

3.7 License Renewal Aging Management

The following programs/activities are credited with the aging management of the Primary Containment. These programs and activities were developed to support renewal of the original operating license for GGNS, Unit 1 that was scheduled to expire on November 1, 2024. The period of extended operation is the 20-year period ending November 1, 2044 (Reference 46).

3.7.1 Containment Leak Rate Program

The Containment Leak Rate Program, also known as the 10 CFR Part 50, Appendix J Program, consists of tests performed in accordance with the regulations and guidance provided in 10 CFR 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors," Option B; RG 1.163, "Performance-Based Containment Leak-Testing Program;" NEI 94-01, "Industry Guideline for Implementing Performance-Based Options of 10 CFR Part 50, Appendix J;" and ANSI/ANS 56.8, "Containment System Leakage Testing Requirements."

The 10 CFR Part 50, Appendix J Aging Management Program is an existing program that provides for detection of pressure boundary degradation due to aging effects such as loss of leakage tightness, loss of material, cracking, loss of sealing or loss of preload in various systems penetrating containment. The program also provides for detection of age-related degradation in material properties of gaskets, O-rings, and packing materials for the primary containment pressure boundary access points.

Containment leakage rate tests (LRTs) are performed to assure that leakage through the containment and systems and components penetrating primary containment does not exceed allowable leakage limits specified in the plant TS. An ILRT is performed during a period of reactor shutdown at the frequency specified in 10 CFR 50, Appendix J, Option B. Performance of the ILRT per 10 CFR 50, Appendix J demonstrates the leak-tightness and structural integrity of the containment. Local leakage rate tests (LLRTs) are performed on isolation valves and containment access penetrations at frequencies that comply with the requirements of 10 CFR 50, Appendix J, Option B.

The ILRT measures overall containment leakage and the LLRT measures the pressure retaining integrity and leakage rates of individual containment penetrations. The parameters monitored are leakage rates of the containment shells; containment liners; and associated welds, penetrations, fittings and other access openings. The leakage rate acceptance criteria meet the requirements of 10 CFR 50, Appendix J, and are part of the CLB.

The 10 CFR Part 50, Appendix J Program does not prevent degradation due to aging effects but provides measures for condition monitoring to detect the degradation prior to loss of intended function. The 10 CFR Part 50, Appendix J Program detects degradation of the containment shell and liner and components that may compromise the containment pressure boundary, including seals and gaskets. The use of pressure tests verifies the pressure retaining integrity of the containment. The Containment LRT demonstrates the leak-tightness of containment isolation barriers.

The Containment Leak Rate Program documents and trends test results in accordance with the requirements and guidance provided in 10 CFR 50, Appendix J. The Containment Leak Rate Program demonstrates that the test results meet the requirements contained in the acceptance criteria. Test results that fail to meet the acceptance criteria defined in the plant TS are reported in accordance with approved procedures that meet the requirements of 10 CFR 50.72 and 10 CFR 50.73.

Evaluations are performed for test or inspection results that do not satisfy established criteria and a Condition Report is initiated to document the issue in accordance with plant administrative procedures.

The 10 CFR Part 50, Appendix B corrective actions program (CAP) ensures that the conditions adverse to quality are promptly corrected. If the deficiency is assessed to be significantly adverse to quality, the cause of the condition is determined, and an action plan is developed to prevent recurrence. Corrective actions are performed in accordance with applicable procedures that meet the requirements of 10 CFR 50, Appendix J and NEI 94-01.

The Containment Leak Rate Program has been effective at managing aging effects. The Containment Leak Rate Program assures the effects of aging are managed such that applicable components will continue to perform their intended functions consistent with the CLB through the period of extended operation.

The Containment Leak Rate Program is consistent with the program described in NUREG-1801, Section XI.S4 (Reference 48) and 10 CFR 50, Appendix J.

3.7.2 Containment Inservice Inspection (CISI) – IWE Program

The CISI – IWE Program at GGNS for ASME Section XI, Subsection IWE is comparable to the program described in NUREG-1801, XI.S1, ASME Section XI, Subsection IWE.

The program performs a general visual examination to assess the general condition of the containment and to detect evidence of degradation that may affect structural integrity or leak tightness. This examination satisfies the requirements of the ASME Boiler and Pressure Vessel Code (to include the 2007 Edition with 2008 Addenda), Section XI, Subsection IWE Examination Category E-A. The requirements of IWA-2210, 2300, 2500, and 2600 are not applicable to Subsection IWE visual examinations per IWE-2100.

Subsection IWE requires examination of coatings that are intended to prevent corrosion. Service Level 1 (SL1) protective coatings are not credited to manage the effects of aging; however, proper maintenance of protective coatings inside containment is essential to ensure operability of post-accident safety systems that rely on water recycled through the containment. GGNS uses the Protective Coatings Monitoring and Maintenance Program as defined in NUREG-1800, AMP

XI.S8 to ensure that the SL1 coatings maintain their intended function and to ensure the operability of the emergency core cooling systems.

The GGNS containment design utilizes the GE BWR Mark III containment and does not have the gap behind the liner plates and the concrete shield wall or a sand pocket region. Therefore, the requirements related to ensuring that the sand pocket area drains and/or the refueling seal drains are clear are not applicable.

The CISI-IWE Program is a condition monitoring program and does not include guidance for the selection of bolting material installation torque or tension and use of lubricants and sealants. Existing plant procedures augment the program to ensure that the selection of bolting material installation torque or tension, and the use of lubricants and sealants is appropriate for the intended purpose. These procedures use similar guidance contained in industry standards to ensure proper specification of bolting material, lubricant, and installation torque.

The CISI Program has been effective at managing aging effects. The CISI Program assures the effects of aging are managed such that applicable components will continue to perform their intended functions consistent with the CLB through the period of extended operation.

The CISI – IWE Program is consistent with the program described in NUREG-1801, Section XI.S1, ASME Section XI, Subsection IWE.

3.7.3 Containment Inservice Inspection (CISI) – IWL Program

The Containment Inservice Inspection (CISI) – IWL Program at GGNS is comparable to the aging management program described in NUREG-1801, XI.S2, ASME Section XI, Subsection IWL.

The program performs general and detailed visual examinations to assess the overall condition of the containment and detect for evidence of degradation that may affect structural integrity or leak tightness. These examinations are used to meet the examination requirements of the ASME Boiler and Pressure Vessel Code (2008 Edition with the 2008 Addenda) Section XI, Subsection IWL Examination Category L-A, Item Numbers L1.11 and L1.12. In accordance with GGNS specific relief requests, these examinations are also used as an alternative to the examinations specified in the 1992 edition with 1992 addenda for IWL Examination Category L-A. The requirements of IWA-2210 are not applicable to Subsection IWL visual examinations as stated in IWL-2100, 2300, 2500, and 2600. The GGNS GE BWR Mark III containment is a reinforced concrete structure with a metal liner and it does not utilize a post-tensioning system. Therefore, IWL requirements pertaining to post-tensioning and expansion of inspection scope do not apply.

The CISI Program has been effective at managing aging effects. The CISI Program assures the effects of aging are managed such that applicable components will continue to perform their intended functions consistent with the CLB through the period of extended operation.

The CISI-IWL Program at GGNS is consistent with the program described in NUREG-1801, XI.S2, ASME Section XI, Subsection IWL.

3.7.4 Protective Coating Monitoring and Maintenance Program

The Protective Coating Program is compared to the program described in NUREG-1801, Section XI.S8, Protective Coating Monitoring and Maintenance Program.

The GGNS Protective Coatings Program is an existing program that monitors and maintains SL1 coatings inside containment. The program provides an effective method to assess coating condition through visual inspections by identifying degraded or damaged coatings and providing a means for repair of identified problem areas. The program addresses all coated surfaces inside containment (e.g., steel liner, structural steel, supports, penetrations, and concrete walls and floors) and some Level III coatings outside containment.

SL1 protective coatings are not credited to manage the effects of aging; however, proper monitoring and maintenance of protective coatings inside containment is essential to ensure operability of post-accident safety systems that rely on water recycled through the containment. The proper monitoring and maintenance of SL1 coatings ensures there is no coating degradation that would impact safety functions.

The Protective Coating Program has been effective at managing aging effects. The Protective Coating Program assures the effects of aging are managed such that applicable components will continue to perform their intended functions consistent with the CLB through the period of extended operation.

The Protective Coating Program is consistent with the program described in NUREG-1801, Section XI.S8, Protective Coating Program, with the following enhancements delineated in Table 3.7.4-1, which will be implemented prior to the period of extended operation.

Table 3.7.4-1, Protective Coating Monitoring and Maintenance Program	
Attributes Affected	**Enhancements**
3. Parameters Monitored or Inspected	Enhancement: Enhance the Protective Coating Program to clarify the parameters monitored or inspected by the program will include the guidance provided in ASTM D5163-08.
4. Detection of Aging Effects	Enhancement: Enhance the Protective Coating Monitoring and Maintenance Program to clarify that detection of aging effects will include inspection of coatings near sumps or screens associated with the Emergency Core Cooling System.
6. Acceptance Criteria	Enhancement: Enhance the Protective Coating Program acceptance criteria to include the guidance of ASTM D 5163-08.

3.8 NRC SER LIMITATIONS AND CONDITIONS

3.8.1 Limitations and Conditions Applicable to NEI 94-01, Revision 2-A

The NRC staff found that the use of NEI TR 94-01, Revision 2, was acceptable for referencing by licensees proposing to amend their TS to permanently extend the ILRT surveillance interval to 15 years, provided the following conditions, as listed in Table 3.8.1-1, are satisfied:

Table 3.8.1-1
NEI 94-01, Revision 2-A Limitations and Conditions

Limitation/Condition (From Section 4.0 of SE)	GGNS Response
For calculating the Type A leakage rate, the licensee should use the definition in the NEI TR 94-01, Revision 2, in lieu of that in ANSI/ANS-56.8-2002. (Refer to SE Section 3.1.1.1.)	GGNS will utilize the definition in NEI 94-01, Revision 3-A, Section 5.0. This definition has remained unchanged from Revision 2-A to Revision 3-A of NEI 94-01.
The licensee submits a schedule of containment inspections to be performed prior to and between Type A tests. (Refer to SE Section 3.1.1.3.)	Reference Section 3.5.4, Table 3.5.4-1 and Figures 3.5.4-1 and 3.5.4-2 of this LAR submittal.
The licensee addresses the areas of the containment structure potentially subjected to degradation. (Refer to SE Section 3.1.3.)	Reference Section 3.5.4, Tables 3.5.4-6 and 3.5.4-7 of this LAR submittal.
The licensee addresses any tests and inspections performed following major modifications to the containment structure, as applicable. (Refer to SE Section 3.1.4.)	There have been no major containment repairs or modifications performed on the GGNS Containment Vessel.
The normal Type A test interval should be less than 15 years. If a licensee must utilize the provision of Section 9.1 of NEI TR 94-01, Revision 2, related to extending the ILRT interval beyond 15 years, the licensee must demonstrate to the NRC staff that it is an unforeseen emergent condition. (Refer to SE Section 3.1.1.2.)	GGNS will follow the requirements of NEI 94-01, Revision 3-A, Section 9.1. This requirement has remained unchanged from Revision 2-A to Revision 3-A of NEI 94-01. In accordance with the requirements of NEI 94-01, Revision 2-A, SER Section 3.1.1.2, GGNS will also demonstrate to the NRC staff that an unforeseen emergent condition exists in the event an extension beyond the 15-year interval is required.
For plants licensed under 10 CFR Part 52, applications requesting a permanent extension of the ILRT surveillance interval to 15 years should be deferred until after the construction and testing of containments for that design have been completed and applicants have confirmed the applicability of NEI 94-01, Revision 2, and EPRI Report No. 1009325, Revision 2, including the use of past containment ILRT data.	Not applicable. GGNS was not licensed under 10 CFR Part 52.

3.9 CONCLUSION

NEI 94-01, Revision 3-A, dated July 2012 (Reference 2), and the limitations and conditions specified in NEI 94-01, Revision 2-A, Section 4.1, dated October 2008 (Reference 3), describe an NRC-accepted approach for implementing the performance-based requirements of 10 CFR 50, Appendix J, Option B. It incorporates the regulatory positions stated in RG 1.163 (Reference 1) and includes provisions for extending Type A intervals to 15 years. NEI 94-01, Revision 3-A, delineates a performance-based approach for determining Type A containment leakage rate surveillance test frequency. GGNS is adopting the guidance of NEI 94-01, Revision 3-A, and the limitations and conditions specified in NEI 94-01, Revision 2-A, for the GGNS, Unit 1, 10 CFR 50, Appendix J testing program plan.

Based on the previous ILRTs conducted at GGNS, Unit 1, Entergy concludes that the one-cycle extension of the containment ILRT interval from 11.5 to 13.5 years represents minimal risk to increased leakage. The risk is minimized by continued Type B and Type C testing performed in accordance with Option B of 10 CFR 50, Appendix J, and the overlapping inspection activities performed as part of the following GGNS inspection programs:

- Containment Inservice Inspection Program – IWE and IWL
- Service Level I Coatings Assessment
- Containment Inspections per TS SR 3.6.5.1.2

This experience is supplemented by risk analysis studies, including the GGNS risk analysis provided in Attachment 3. The risk assessment concludes that increasing the ILRT interval on a permanent basis to a one-in-fifteen-year frequency is not considered to be significant because it represents only a small change in the GGNS risk profile.

4.0 REGULATORY EVALUATION

4.1 Applicable Regulatory Requirements/Criteria

The proposed change has been evaluated to determine whether applicable regulations and requirements continue to be met.

The requirements to perform testing of the primary reactor containment are set forth in 10 CFR 50.54(o) and 10 CFR 50, Appendix J. Both of these sections address criteria established in 10 CFR 50, Appendix A, "General Design Criteria" (GDC): GDC 50 (Containment Design Basis); GDC 51 (Fracture Prevention of Containment Pressure Boundary); GDC 52 (Capability for Containment Leakage Rate Testing); and, GDC 53 (Provisions for Containment Testing and Inspection). A discussion of the GGNS conformance with these GDC is provided in the GGNS Updated Final Safety Analysis Report (UFSAR) Chapter 3.1. Entergy has determined that the proposed change does not require any additional exemptions or relief from regulatory requirements and does not affect conformance with any GDC as described in the UFSAR. However, this change does propose an extension of the frequency for performance of the Type A Integrated Leakage Rate Test (ILRT) and the Drywell Bypass Leakage Rate Test (DWBT). The requirement to perform a drywell bypass leakage rate test is derived from 10 CFR 50.36.

10 CFR 50.54(o) requires primary reactor containments for water-cooled power reactors to be subject to the requirements of Appendix J to 10 CFR Part 50, "Leakage Rate Testing of

Containment of Water Cooled Nuclear Power Plants." Appendix J specifies containment leakage testing requirements, including the types required to ensure the leak-tight integrity of the primary reactor containment and systems and components which penetrate the containment. In addition, Appendix J discusses leakage rate acceptance criteria, test methodology, frequency of testing and reporting requirements for each type of test.

The adoption of the Option B performance-based containment leakage rate testing for Type A, Type B, and Type C testing did not alter the basic method by which Appendix J leakage rate testing is performed; However, it did alter the frequency at which Type A, Type B, and Type C containment leakage tests must be performed. Under the performance-based option of 10 CFR Part 50, Appendix J, the test frequency is based upon an evaluation that reviewed "as-found" leakage history to determine the frequency for leakage testing which provides assurance that leakage limits will be maintained. The change to the Type A test frequency did not directly result in an increase in containment leakage. Similarly, the proposed change to the Type C test frequencies will not directly result in an increase in containment leakage

10 CFR 50.36(c)(3), "Surveillance requirements," states, in part, that TS shall include the "requirements relating to test, calibration or inspection to assure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions for operation will be met." This proposed change revises TS 5.5.12 and SR 3.6.5.1.1, to add the date-related information for the next Type A test performance, along with the date-related information for the next DWBT. Therefore, this 10 CFR 50.36 requirement continues to be met by this change.

10 CFR 50.36(c)(5), "Administrative controls," requires that "provisions relating to organization and management, procedures, recordkeeping, review and audit, and reporting necessary to assure operation of the facility in a safe manner" will be included in the TS. 10 CFR 50, Appendix J, Option B, Section V.B, "Implementation," requires that the implementation document used to develop a performance-based leakage testinq program be included by general reference in the TS. The Appendix J Testing Program is included in the Administrative Controls section of the GGNS TS, as TS 5.5.12, "10 CFR 50, Appendix J, Testing Program." This proposed change does not remove this administrative control requirement, but simply revises TS 5.5.12, to extend the frequency for performing the Type A ILRT to 13.5 years. In addition, this proposed change will revise SR 3.6.5.1.1 to extend the frequency for performing the DWBT to 13.5 years. Therefore, this 10 CFR 50.36 requirement continues to be met by this proposed change.

EPRI TR-1009325, "Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals," Revision 2-A (Reference 9), provided a risk impact assessment for optimized ILRT intervals up to 15 years, utilizing current industry performance data and risk informed guidance. NEI 94-01, Revision 3-A, Section 9.2.3.1 (Reference 2), states that Type A ILRT intervals of up to 15 years are allowed by this guideline. EPRI Report 1018243 (formerly TR-1009325, Revision 2-A), indicates that, in general, the risk impact associated with ILRT interval extensions for intervals up to 15 years is small. However, plant-specific confirmatory analyses are required.

The NRC staff reviewed NEI TR 94-01, Revision 2, and EPRI Report No. 1009325, Revision 2. For NEI TR 94-01, Revision 2, the NRC determined that it described an acceptable approach for implementing the optional performance-based requirements of Option B to 10 CFR 50, Appendix J. This guidance includes provisions for extending Type A ILRT intervals up to 15 years and incorporates the regulatory positions stated in RG 1.163. The NRC finds that the Type A testing methodology, as described in ANSI/ANS-56.8-2002 (Reference 30), and the modified testing

frequencies recommended by NEI TR 94-01, Revision 2, serve to ensure continued leakage integrity of the containment structure. Type B and Type C testing ensures that individual penetrations are essentially leak tight. In addition, aggregate Type B and Type C leakage rates support the leakage tightness of primary containment by minimizing potential leakage paths.

For EPRI Report No. 1009325, Revision 2, a risk-informed methodology using plant-specific risk insights and industry ILRT performance data to revise ILRT surveillance frequencies, the NRC staff finds that the proposed methodology satisfies the key principles of risk-informed decision making applied to changes to TS as delineated in RG1.174 (Reference 28) and RG 1.177 (Reference 47), "An Approach for Plant-Specific, Risk-Informed Decision making: Technical Specifications." The NRC, therefore, found that this guidance was acceptable for referencing by licensees proposing to amend their TS in regard to containment leakage rate testing, subject to the limitations and conditions noted in Section 4.2 of the SER.

The NRC staff reviewed NEI TR 94-01, Revision 3, and determined that it described an acceptable approach for implementing the optional performance-based requirements of Option B to 10 CFR 50, Appendix J, as modified by the limitations and conditions summarized in Section 4.0 of the associated SE. This guidance included provisions for extending Type C LLRT intervals up to 75 months. Type C testing ensures that individual CIVs are essentially leak tight. In addition, aggregate Type C leakage rates support the leakage tightness of primary containment by minimizing potential leakage paths. The NRC staff, therefore, found that this guidance, as modified to include two limitations and conditions, was acceptable for referencing by licensees proposing to amend their TS in regard to containment leakage rate testing. Any applicant may reference NEI TR 94-01, Revision 3, as modified by the associated SER and approved by the NRC, and the limitations and conditions specified in NEI 94-01, Revision 2-A, dated October 2008, in a licensing action to satisfy the requirements of Option B to 10 CFR 50, Appendix J.

4.2 Precedent

This LAR is similar in nature to the following license amendments for a one-cycle extension to the Type A Test frequency, as previously authorized by the NRC in the referenced Safety Evaluations:

- Grand Gulf Nuclear Station, Unit 1, Amendment 214, dated December 29, 2017 (Reference 23)
- McGuire Nuclear Station, Units 1 and 2, Amendments 290 and 269, dated September 26, 2016 (Reference 22)

4.3 No Significant Hazards Consideration

Entergy Operations, Inc. (Entergy) has evaluated whether or not a significant hazards consideration is involved with the proposed amendment by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

1. Does the proposed amendment involve a significant increase in the probability or consequences of an accident previously evaluated?

Response: No.

The proposed amendment to the Technical Specifications (TS) involves a one-cycle extension of the Grand Gulf Nuclear Station, Unit 1 (GGNS) Type A integrated leakage rate test (ILRT) and the drywell bypass leakage rate test (DWBT) intervals to 13.5 years.

The proposed extensions do not involve either a physical change to the plant or a change in the manner in which the plant is operated or controlled. The Containment is designed to provide an essentially leak tight barrier against the uncontrolled release of radioactivity to the environment for postulated accidents. As such, the Containment and the testing requirements invoked to periodically demonstrate the integrity of the Containment exist to ensure the plant's ability to mitigate the consequences of an accident, and do not involve the prevention or identification of any precursors of an accident.

The change in Type A test frequency 13.5 years, measured as an increase to the total integrated plant risk for those accident sequences influenced by Type A testing, based on the internal events (IE) probabilistic risk analysis (PRA) is less than 0.006 person-rem/year for GGNS. Electric Power Research Institute (EPRI) Report No. 1009325, Revision 2-A states that a very small population is defined as an increase of ≤ 1.0 person-rem per year or ≤ 1% of the total population dose, whichever is less restrictive for the risk impact assessment of the extended ILRT intervals. This is consistent with the Nuclear Regulatory Commission (NRC) Final Safety Evaluation for Nuclear Energy Institute (NEI) 94-01 and EPRI Report No. 1009325. Moreover, the risk impact when compared to other severe accident risks is negligible. Therefore, this proposed extension does not involve a significant increase in the probability of an accident previously evaluated.

In addition, as documented in NUREG-1493, "Performance-Based Containment Leak-Test Program," dated September 1995, Types B and C tests have identified a very large percentage of containment leakage paths, and the percentage of containment leakage paths that are detected only by Type A testing is very small. The GGNS Type A test history supports this conclusion.

The integrity of the Containment is subject to two types of failure mechanisms that can be categorized as: (1) activity-based, and (2) time-based. Activity-based failure mechanisms are defined as degradation due to system and/or component modifications or maintenance. The local leakage rate test (LLRT) requirements and administrative controls such as configuration management and procedural requirements for system restoration ensure that Containment integrity is not degraded by plant modifications or maintenance activities. The design and construction requirements of the Containment, combined with the Containment inspections performed in accordance with the American Society of Mechanical Engineers (ASME) Section XI, and TS requirements serve to

provide a high degree of assurance that the Containment would not degrade in a manner that is detectable only by a Type A test. Based on the above, the proposed Type A test interval extension does not significantly increase the consequences of an accident previously evaluated.

Therefore, the proposed change does not result in a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the proposed change create the possibility of a new or different kind of accident from any accident previously evaluated?

Response: No.

The proposed amendment to the GGNS TS involves a one-cycle extension of the Type A ILRT and the DWBT intervals to 13.5 years. The Containment and the testing requirements to periodically demonstrate the integrity of the Containment exist to ensure the plant's ability to mitigate the consequences of an accident do not involve any accident precursors or initiators. The proposed change does not involve a physical change to the plant (i.e., no new or different type of equipment will be installed) or a change to the manner in which the plant is operated or controlled.

Therefore, the proposed change does not create the possibility of a new or different kind of accident from any previously evaluated.

3. Does the proposed change involve a significant reduction in a margin of safety?

Response: No.

The proposed amendment to the GGNS TS involves a one-cycle extension of the Type A ILRT and the DWBT intervals to 13.5 years. This amendment does not alter the manner in which safety limits, limiting safety system set points, or limiting conditions for operation are determined. The specific requirements and conditions of the TS 10 CFR 50, Appendix J Testing Program for Containment leakage rate testing exist to ensure that the degree of Containment structural integrity and leak-tightness that is considered in the plant safety analysis are maintained. The overall containment leak rate limit specified by TS is maintained.

The design, operation, testing methods, and acceptance criteria for Types A, B, and C Containment leakage tests specified in applicable Codes and Standards would continue to be met with the acceptance of this proposed change, since these are not affected by the proposed changes to the Type A test interval.

Therefore, the proposed change does not involve a significant reduction in a margin of safety.

Based on the above, Entergy concludes that the proposed amendment does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of no significant hazards consideration is justified.

4.4 Conclusion

In conclusion, based on the considerations discussed above, (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

5.0 ENVIRONMENTAL CONSIDERATION

A review has determined that the proposed amendment would change a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, or would change an inspection or surveillance requirement. However, the proposed amendment does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed amendment meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendment.

6.0 REFERENCES

1. Regulatory Guide (RG) 1.163, "Performance-Based Containment Leak-Test Program," September 1995.

2. Nuclear Energy Institute (NEI) 94-01, Revision 3-A, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J," July 2012.

3. NEI 94-01, Revision 2-A, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J," October 2008.

4. NEI 94-01, Revision 0, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J," July 1995.

5. NUREG-1493, Performance-Based Containment Leak-Test Program, January 1995.

6. EPRI TR-104285, "Risk Impact Assessment of Revised Containment Leak Rate Testing Intervals," August 1994.

7. NRC letter to NEI, 'Final Safety Evaluation for Nuclear Energy Institute (NEI) Topical Report (TR) 94-01, Revision 2, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J," and Electric Power Research Institute (EPRI) Report No. 1009325, Revision 2, August 2007, "Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals" (TAC No. MC9663), (ADAMS Accession No. ML081140105), dated June 25, 2008.

8. NRC letter to NEI, ‘Final Safety Evaluation of Nuclear Energy Institute (NEI) Report 94-01, Revision 3, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J" (TAC No. ME2164), (ADAMS Accession No. ML121030286), dated June 8, 2012.

9. EPRI TR-1009325, "Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals, Revision 2-A, EPRI, Palo Alto, CA: 2008."

10. NRC letter to Entergy Operations, Inc (Entergy), "Grand Gulf Nuclear Station, Unit 1 – Issuance of Exemption from the Requirements of 10 CFR Part 50, Appendix J, Section III.D (TAC No. 87209)," (ADAMS Accession No. ML021480397), dated April 26, 1995.

11. NRC letter to Entergy, "Issuance of Amendment No. 126 to Facility Operating License No. NPF-29 – Grand Gulf Nuclear Station, Unit 1 (TAC No. M94176)," (ADAMS Accession Nos. ML021480466 and ML021490103), dated August 1, 1996.

12. NRC letter to Entergy, "Issuance of Amendment No. 128 to Facility Operating License No. NPF-29 – Grand Gulf Nuclear Station, Unit 1 (TAC No. M95338)," (ADAMS Accession No. ML021490101), dated October 18, 1996.

13. NRC letter to Entergy, "Issuance of Amendment No. 135 to Facility Operating License No. NPF-29 – Grand Gulf Nuclear Station, Unit 1 (TAC No. M99879)," (ADAMS Accession No. ML021490221), dated April 6, 1998.

14. NRC letter to Entergy, "Grand Gulf Nuclear Station, Unit 1 – Issuance of Amendment [No. 145] Re: Full-Scope Implementation of an Alternative Accident Source Term (TAC No. MA8065)," (ADAMS Accession No. ML010780172), dated March 14, 2001.

15. NRC letter to Entergy, "Grand Gulf Nuclear Station, Unit 1 – Issuance of Amendment [No. 164] Re: One-Time Extension of the Integrated Leak Rate Test and Drywell Bypass Test Interval (TAC No. MB8940)," (ADAMS Accession No. ML040300152), dated January 28, 2004.

16. NRC letter to Entergy, "Grand Gulf Nuclear Station, Unit 1 – Issuance of Amendment [No. 168] Re: Containment Air Lock Leak Rate Test Acceptance Criteria (TAC No. MC5539)," (ADAMS Accession No. ML051540277), dated July 12, 2005.

17. NRC letter to Entergy, "Grand Gulf Nuclear Station, Unit 1 – Issuance of Amendment [No. 176] Re: Change to Technical Specifications to Allow Certain Types of Relief Valves to be Used as Isolation Devices (TAC No. MD4676)," (ADAMS Accession No. ML072140501), dated August 24, 2007.

18. NRC letter to Entergy, "Grand Gulf Nuclear Station, Unit 1 - Issuance of Amendment [No. 191] Re: Extended Power Uprate (TAC No. ME4679)," (ADAMS Accession No. ML121210020), dated July 18, 2012.

19. NRC letter to Entergy, "Grand Gulf Nuclear Station, Unit 1 – Issuance of Amendment No. 197 Re: Revise Technical Specification Surveillance Requirement Frequencies from 18- to 24-Month Fuel Cycle Intervals (TAC No. ME9764)," (ADAMS Accession No. ML13343A109), dated December 26, 2013.

20. NRC letter to Entergy, "Grand Gulf Nuclear Station, Unit 1 – Issuance of Amendment [No. 209] Re: Revision of Technical Specifications for Containment Leak Rate Testing (CAC No. MF6310)," (ADAMS Accession No. ML16011A247), dated February 17, 2016.

21. NRC letter to Entergy, "River Bend Station, Unit 1 – Issuance of Amendment Re: Extension of Containment Leakage Tests Frequency (CAC No. MF7037)," (ADAMS Accession No. ML16287A599), dated October 27, 2016.

22. NRC letter to Duke Energy Carolinas, LLC, "McGuire Nuclear Station, Units 1 and 2 - Issuance of Amendments Regarding One-Time Extension of Appendix J Type A Integrated Leakage Rate Test Interval (CAC Nos. MF7407 and MF7408)," (ADAMS Accession No. ML16236A053), dated September 26, 2016.

23. NRC letter to Entergy, "Grand Gulf Nuclear Station, Unit 1 – Issuance of Amendment [No. 214] Re: One Cycle Extension of Appendix J Type A Integrated Leakage Test and Drywell Bypass Test Interval (CAC No. MF9461; EPID L-2016-LLA-0040)," (ADAMS Accession No. ML17334A739), dated December 29, 2017.

24. NRC letter to Entergy, "Grand Gulf Nuclear Station, Unit 1 – Issuance of Amendment No. 219, Re: Adoption of Technical Specifications Task Force (TSTF) Traveler TSTF-425, Revision 3, 'Relocate Surveillance Frequencies to Licensee Control – RITSTF Initiative 5B' (EPID L-2018-LLA-0106)," (ADAMS Accession No. ML19094A799), dated June 11, 2019.

25. Memorandum from M. J. Wentzel (NRC) to R. J. Pascarelli (NRC), "Safety Evaluation Input for Grand Gulf Nuclear Station Unit 1, License Amendment Request to Implement Technical Specification Task Force-425, Revision 3, Relocate Surveillance Frequencies to Licensee Control," (ADAMS Accession No. ML19018A269), dated March 12, 2019.

26. Interim Guidance for Performing Risk Impact Assessments in Support of One-Time Extensions for Containment Integrated Leakage Rate Test Surveillance Intervals, Revision 4, developed for NEI by EPRI and Data Systems and Solutions, October 2001.

27. NRC letter to Entergy, "Grand Gulf Nuclear Station, Unit 1 – Issuance of Amendment [No. 205] Regarding Maximum Extended Load Line Limit Analysis Plus (TAC No. MF2798)," (ADAMS Accession No. ML15229A219), dated August 31, 2015.

28. RG 1.174, Revision 3, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," dated January 2018.

29. Constellation Nuclear letter to NRC, "Response to Request for Additional Information Concerning the License Amendment Request for a One-Time Integrated Leakage Rate Test Extension,", dated March 27, 2002.

30. ANSI/ANS-56.8-2002, "Containment System Leakage Testing Requirements," dated November 27, 2002

31. EPRI TR-1018243, "Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals: Revision 2-A of 1009325," dated October 2008.

32. Entergy Calculation PSA-GGNS-01, Revision 1, Grand Gulf Nuclear Station, "GGNS PRA Results Summary Report," December 2018.

33. ASME/ANS RA-Sa-2009, Addenda to ASME/ANS RA-S-2008: Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications.

34. "BWROG PSA Peer Review Certification Implementation Guidelines," Revision 3, January 1997.

35. BWROG/PSA-9707, "Grand Gulf Nuclear Station PSA Peer Review Certification Report," October 1997.

36. RSC 14-15/PSA-GGNS-01-QU, "Grand Gulf Nuclear Station Probabilistic Risk Assessment Quantification, Sensitivity, and Uncertainty Analysis Work Package," Revision 0, August 2015.

37. "Grand Gulf Nuclear Station PRA Peer Review Report Using ASME/ANS PRA Standard Requirements (Internal Events and Internal Flooding at Power)," February 2016.

38. PSA-GGNS-01-FNO-RES, "Resolution of GGNS PRA Peer Review Facts and Observations," Revision 0, September 2017.

39. NEI letter to NRC, "Final Revision of Appendix X to NEI 05-04/07-12/12-06, "Close Out of Facts and Observations (F&Os)," (ADAMS Accession Nos. ML17086A431 and ML17086A451), dated February 21, 2017.

40. NRC letter to NEI, "U.S. Nuclear Regulatory Commission Acceptance on Nuclear Energy Institute Appendix X to Guidance 05-04, 07-12, and 12-13, Close-Out of Facts and Observations (F&Os)," (ADAMS Accession No. ML17079A427), dated May 3, 2017.

41. PSA-GGNS-01-FNO-CLOS, "GGNS PSA – Peer Review Findings Closure," Revision 0, dated September 2017.

42. GGNS-94-0054, "Grand Gulf Nuclear Station Engineering Report for Individual Plant Examination of External Events," Revision 1, dated November 1995.

43. NRC, Generic Issue 199 (GI-199), "Enclosure 1: Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern United States on Existing Plants: Safety/Risk Assessment," (ADAMS Accession Nos. ML100270582 and ML100270639), dated August 2010.

44. GGNS-95-0041, "Grand Gulf Nuclear Station Engineering Report for Individual Plant Examination of External Events: Fire," Revision 0, dated October 1996.

45. RG 1.200, Revision 2, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," dated March 2009.

46. NRC Safety Evaluation Report Related to the License Renewal of Grand Gulf Nuclear Station, Unit 1, Docket No. 50-416, (ADAMS Accession No. ML16288A185) dated October 2016.

47. RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," Revision 1, (ADAMS Accession No. ML100910008), dated May 2011.

48. NUREG-1801, Rev 2, "Generic Aging Lessons Learned (GALL) Report," (ADAMS Accession No. ML103490041), dated December 2010.

49. Generic Letter 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991.

50. NUREG-2122, "Glossary of Risk-Related Terms in Support of Risk-Informed Decision Making," dated November 2013.

51. NUREG-1434, Volume 1, Revision 4.0, "Standard Technical Specifications, General Electric BWR/6 Plants," dated April 2012.

52. Entergy letter to NRC, "License Amendment Request for Permanent Extension of Appendix J Type A Integrated Leakage Rate Test Frequencies," (ADAMS Accession No. ML20050R656), dated February 19, 2020.

Attachment 1 to Enclosure

GNRO-2020/00006

Markup of Technical Specification Pages

TS Page
3.6-53
5.0-16

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.6.5.1.1	Verify bypass leakage is less than or equal to the bypass leakage limit. However, during the first unit startup following drywell bypass leak rate testing performed in accordance with this SR, the acceptance criterion is leakage ≤ 10% of the bypass leakage limit.	24 months following two consecutive tests with bypass leakage greater than the bypass leakage limit until two consecutive tests are less than or equal to the bypass leakage limit AND 48 months following a test with bypass leakage greater than the bypass leakage limit AND ----------NOTE-------- SR 3.0.2 is not applicable for extensions > 12 months. ------------------------ In accordance with the Surveillance Frequency Control Program except next drywell bypass leak rate test performed after the October 19, 2008 test shall be performed no later than the plant restart after the End of Cycle ~~22~~ 23 Refueling Outage

(continued)

5.5 Programs and Manuals (continued)

5.5.11 Technical Specifications (TS) Bases Control Program

This program provides a means for processing changes to the Bases of these Technical Specifications.

a. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

b. Licensees may make changes to Bases without prior NRC approval provided the changes do not require either of the following:

1. A change in the TS incorporated in the license; or

2. A change to the updated FSAR or Bases that requires NRC approval pursuant to 10 CFR 50.59.

c. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the UFSAR.

d. Proposed changes that do not meet the criteria of either Specification 5.5.11.b.1 or Specification 5.5.11.b.2 above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

5.5.12 10 CFR 50, Appendix J, Testing Program

23

This program establishes the leakage rate testing program of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be implemented in accordance with the Safety Evaluation issued by the Office of Nuclear Reactor Regulation dated April 26, 1995 (GNRI-95/00087) as modified by the Safety Evaluation issued for Amendment No. 135 to the Operating License, except that the next Type A test performed after the October 19, 2008 Type A test shall be performed no later than the plant restart after the End of Cycle ~~22~~ Refueling Outage. For Type B and Type C local leakage rate testing, this program shall be in accordance with the guidelines contained in NEI 94-01, Revision 3-A, “Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J,” dated July 2012. Consistent with standard scheduling practices for Technical Specifications required surveillances, intervals for the recommended surveillance frequency for Type A testing may be extended by up to 25 percent of the test interval, not to exceed 15 months. The calculated peak containment internal pressure for the design basis loss of coolant accident, Pa, is 12.1 psig.

(continued)

Attachment 2 to Enclosure

GNRO-2020/00013

Retyped Technical Specification Pages

<u>TS Page</u>
3.6-53
5.0-16

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.5.1.1	Verify bypass leakage is less than or equal to the bypass leakage limit. However, during the first unit startup following drywell bypass leak rate testing performed in accordance with this SR, the acceptance criterion is leakage ≤ 10% of the bypass leakage limit.	24 months following two consecutive tests with bypass leakage greater than the bypass leakage limit until two consecutive tests are less than or equal to the bypass leakage limit AND 48 months following a test with bypass leakage greater than the bypass leakage limit AND ----------NOTE-------- SR 3.0.2 is not applicable for extensions > 12 months. ------------------------ In accordance with the Surveillance Frequency Control Program except next drywell bypass leak rate test performed after the October 19, 2008 test shall be performed no later than the plant restart after the End of Cycle 23 Refueling Outage

(continued)

5.5 Programs and Manuals (continued)

5.5.11 Technical Specifications (TS) Bases Control Program

This program provides a means for processing changes to the Bases of these Technical Specifications.

a. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

b. Licensees may make changes to Bases without prior NRC approval provided the changes do not require either of the following:

1. A change in the TS incorporated in the license; or

2. A change to the updated FSAR or Bases that requires NRC approval pursuant to 10 CFR 50.59.

c. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the UFSAR.

d. Proposed changes that do not meet the criteria of either Specification 5.5.11.b.1 or Specification 5.5.11.b.2 above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

5.5.12 10 CFR 50, Appendix J, Testing Program

This program establishes the leakage rate testing program of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be implemented in accordance with the Safety Evaluation issued by the Office of Nuclear Reactor Regulation dated April 26, 1995 (GNRI-95/00087) as modified by the Safety Evaluation issued for Amendment No. 135 to the Operating License, except that the next Type A test performed after the October 19, 2008 Type A test shall be performed no later than the plant restart after the End of Cycle 23 Refueling Outage. For Type B and Type C local leakage rate testing, this program shall be in accordance with the guidelines contained in NEI 94-01, Revision 3-A, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J," dated July 2012. The calculated peak containment internal pressure for the design basis loss of coolant accident, Pa, is 12.1 psig.

(continued)

Attachment 3 to Enclosure

GNRO-2020/00013

Grand Gulf Nuclear Station: Evaluation of Risk Significance of Permanent ILRT Extension

JENSEN HUGHES

Advancing the Science of Safety

Grand Gulf Nuclear Station:
Evaluation of Risk Significance of Permanent ILRT Extension

54007-CALC-01

Prepared for:

Grand Gulf Nuclear Station

Project Number: 1RCA54007
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Revision: 1

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REVISION RECORD SUMMARY

Revision	Revision Summary
0	Initial issue
1	Revised Sections 4.0, 5.1.2, and A.1 to state model Revision 4b is the model of record.

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1.0 PURPOSE

The purpose of this analysis is to provide a risk assessment of permanently extending the currently allowed containment Type A Integrated Leak Rate Test (ILRT) interval to fifteen years. The extension would allow for substantial cost savings as the ILRT could be deferred for additional scheduled refueling outages for the Grand Gulf Nuclear Station (GGNS). The risk assessment follows the guidelines from NEI 94-01, Revision 3-A [Reference 1], the methodology used in EPRI TR-104285 [Reference 2], the NEI “Interim Guidance for Performing Risk Impact Assessments in Support of One-Time Extensions for Containment Integrated Leakage Rate Test Surveillance Intervals” from November 2001 [Reference 3], the NRC regulatory guidance on the use of Probabilistic Risk Assessment (PRA) as stated in Regulatory Guide 1.200 [Reference 59] as applied to ILRT interval extensions, risk insights in support of a request for a plant’s licensing basis as outlined in Regulatory Guide (RG) 1.174 [Reference 4], the methodology used for Calvert Cliffs to estimate the likelihood and risk implications of corrosion-induced leakage of steel liners going undetected during the extended test interval [Reference 5], and the methodology used in EPRI 1018243, Revision 2-A of EPRI 1009325 [Reference 24].

2.0 SCOPE

Revisions to 10CFR50, Appendix J (Option B) allow individual plants to extend the Integrated Leak Rate Test (ILRT) Type A surveillance testing frequency requirement from three in ten years to at least once in ten years. The revised Type A frequency is based on an acceptable performance history defined as two consecutive periodic Type A tests at least 24 months apart in which the calculated performance leakage rate was less than limiting containment leakage rate of $1L_a$.

The basis for the current 10-year test interval is provided in Section 11.0 of NEI 94-01, Revision 0, and established in 1995 during development of the performance-based Option B to Appendix J. Section 11.0 of NEI 94-01 states that NUREG-1493, “Performance-Based Containment Leak Test Program,” September 1995 [Reference 6], provides the technical basis to support rulemaking to revise leakage rate testing requirements contained in Option B to Appendix J. The basis consisted of qualitative and quantitative assessment of the risk impact (in terms of increased public dose) associated with a range of extended leakage rate test intervals. To supplement the NRC’s rulemaking basis, NEI undertook a similar study. The results of that study are documented in Electric Power Research Institute (EPRI) Research Project TR-104285, “Risk Impact Assessment of Revised Containment Leak Rate Testing Intervals.”

The NRC report on performance-based leak testing, NUREG-1493, analyzed the effects of containment leakage on the health and safety of the public and the benefits realized from the containment leak rate testing. In that analysis, it was determined that for a representative BWR plant (i.e., Peach Bottom), that increasing the containment leak rate from the nominal 0.5% per day to 5 percent per day leads to a barely perceptible increase in total population exposure, and increasing the leak rate to 50% per day increases the total population exposure by less than 1%. Because ILRTs represent substantial resource expenditures, it is desirable to show that extending the ILRT interval will not lead to a substantial increase in risk from containment isolation failures to support a reduction in the test frequency for GGNS.

NEI 94-01 Revision 3-A supports using EPRI Report No. 1009325 Revision 2-A (EPRI 1018243), “Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals,” for performing risk impact assessments in support of ILRT extensions [Reference 24]. The Guidance provided in Appendix H of EPRI 1018243 builds on the EPRI Risk Assessment methodology, EPRI TR-104285. This methodology is followed to determine the appropriate risk

information for use in evaluating the impact of the proposed ILRT changes.

It should be noted that containment leak-tight integrity is also verified through periodic in-service inspections conducted in accordance with the requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Section XI. More specifically, Subsection IWE provides the rules and requirements for in-service inspection of Class MC pressure-retaining components and their integral attachments, and of metallic shell and penetration liners of Class CC pressure-retaining components and their integral attachments in light-water cooled plants. Furthermore, NRC regulations 10 CFR 50.55a(b)(2)(ix)(E) require licensees to conduct visual inspections of the accessible areas of the interior of the containment. The associated change to NEI 94-01 will require that visual examinations be conducted during at least three other outages, and in the outage during which the ILRT is being conducted. These requirements will not be changed as a result of the extended ILRT interval. In addition, Appendix J, Type B local leak tests performed to verify the leak-tight integrity of containment penetration bellows, airlocks, seals, and gaskets are also not affected by the change to the Type A test frequency.

The acceptance guidelines in RG 1.174 are used to assess the acceptability of this permanent extension of the Type A test interval beyond that established during the Option B rulemaking of Appendix J. RG 1.174 defines very small changes in the risk-acceptance guidelines as increases in Core Damage Frequency (CDF) less than 10^{-6} per reactor year and increases in Large Early Release Frequency (LERF) less than 10^{-7} per reactor year. Since containment accident pressure is not required in support of ECCS performance to mitigate design basis accidents at GGNS [Reference 36], the ILRT extension does not impact CDF. Therefore, the more relevant risk-impact metric is LERF. RG 1.174 also defines small changes in LERF as below 10^{-6} per reactor year. RG 1.174 discusses defense-in-depth and encourages the use of risk analysis techniques to help ensure and show that key principles, such as the defense-in-depth philosophy, are met. Therefore, the increase in the Conditional Containment Failure Probability (CCFP), which helps ensure the defense-in-depth philosophy is maintained, is also calculated.

Regarding CCFP, changes of up to 1.1% have been accepted by the NRC for the one-time requests for extension of ILRT intervals. In context, it is noted that a CCFP of 1/10 (10%) has been approved for application to evolutionary light water designs. Given these perspectives, a change in the CCFP of up to 1.5% is assumed to be small [Reference 1].

In addition, the total annual risk (person rem/year population dose) is examined to demonstrate the relative change in this parameter. While no acceptance guidelines for these additional figures of merit are published, examinations of NUREG-1493 and Safety Evaluation Reports (SER) for one-time interval extension (summarized in Appendix G of Reference 24) indicate a range of incremental increases in population dose that have been accepted by the NRC. The range of incremental population dose increases is from ≤0.01 to 0.2 person-rem/year and/or 0.002% to 0.46% of the total accident dose. The total doses for the spectrum of all accidents (NUREG-1493 [Reference 6], Figure 7-2) result in health effects that are at least two orders of magnitude less than the NRC Safety Goal Risk. Given these perspectives, a "small" population dose is defined as an increase from the baseline interval (3 tests per 10 years) dose of ≤1.0 person-rem per year or 1% of the total baseline dose, whichever is less restrictive for the risk impact assessment of the proposed extended ILRT interval [Reference 1].

For those plants that credit containment overpressure for the mitigation of design basis accidents, a brief description of whether overpressure is required should be included in this section. In addition, if overpressure is included in the assessment, other risk metrics such as CDF should be described and reported.

3.0 REFERENCES

The following references were used in this calculation:

1. *Revision 3-A to Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J*, NEI 94-01, July 2012.
2. *Risk Impact Assessment of Revised Containment Leak Rate Testing Intervals*, EPRI, Palo Alto, CA, EPRI TR-104285, August 1994.
3. *Interim Guidance for Performing Risk Impact Assessments in Support of One-Time Extensions for Containment Integrated Leakage Rate Test Surveillance Intervals*, Revision 4, developed for NEI by EPRI and Data Systems and Solutions, October 2001.
4. An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis, Regulatory Guide 1.174, Revision 3, January 2018.
5. *Response to Request for Additional Information Concerning the License Amendment Request for a One-Time Integrated Leakage Rate Test Extension*, Letter from Mr. C. H. Cruse (Calvert Cliffs Nuclear Power Plant) to NRC Document Control Desk, Docket No. 50-317, March 27, 2002.
6. Performance-Based Containment Leak-Test Program, NUREG-1493, September 1995.
7. *Evaluation of Severe Accident Risks: Peach Bottom Unit 2*, Main Report NUREG/CR-4551, SAND86-1309, Volume 4, Revision 1, Part 1, October 1990.
8. Letter from R. J. Barrett (Entergy) to U. S. Nuclear Regulatory Commission, IPN-01-007, January 18, 2001.
9. United States Nuclear Regulatory Commission, Indian Point Nuclear Generating Unit No. 3 – Issuance of Amendment Re: Frequency of Performance-Based Leakage Rate Testing (TAC No. MB0178), April 17, 2001.
10. *Impact of Containment Building Leakage on LWR Accident Risk*, Oak Ridge National Laboratory, NUREG/CR-3539, ORNL/TM-8964, April 1984.
11. *Reliability Analysis of Containment Isolation Systems*, Pacific Northwest Laboratory, NUREG/CR-4220, PNL-5432, June 1985.
12. Technical Findings and Regulatory Analysis for Generic Safety Issue II.E.4.3 'Containment Integrity Check', NUREG-1273, April 1988.
13. *Review of Light Water Reactor Regulatory Requirements*, Pacific Northwest Laboratory, NUREG/CR-4330, PNL-5809, Volume 2, June 1986.
14. Shutdown Risk Impact Assessment for Extended Containment Leakage Testing Intervals Utilizing ORAM™, EPRI, Palo Alto, CA, TR-105189, Final Report, May 1995.
15. *Severe Accident Risks: An Assessment for Five U. S. Nuclear Power Plants*, NUREG-1150, December 1990.
16. United States Nuclear Regulatory Commission, Reactor Safety Study, WASH-1400, October 1975.
17. Calculation PSA-GGNS-01, Revision 1, Grand Gulf Nuclear Station, "GGNS PRA Results Summary Report," December 2018.
18. Calculation PSA-GGNS-01-LE, Revision 1, Grand Gulf Nuclear Station, "GGNS PSA – Large Early Release Frequency."

19. Grand Gulf Nuclear Station, Application for Renewed Operating License, Appendix E – Environmental Report, 2011.
20. Anthony R. Pietrangelo, One-time extensions of containment integrated leak rate test interval – additional information, NEI letter to Administrative Points of Contact, November 30, 2001.
21. Letter from J. A. Hutton (Exelon, Peach Bottom) to U. S. Nuclear Regulatory Commission, Docket No. 50-278, License No. DPR-56, LAR-01-00430, dated May 30, 2001.
22. *Risk Assessment for Joseph M. Farley Nuclear Plant Regarding ILRT (Type A) Extension Request*, prepared for Southern Nuclear Operating Co. by ERIN Engineering and Research, P0293010002-1929-030602, March 2002.
23. Letter from D. E. Young (Florida Power, Crystal River) to U. S. Nuclear Regulatory Commission, 3F0401-11, dated April 25, 2001.
24. *Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals*, Revision 2-A of 1009325, EPRI, Palo Alto, CA. 1018243, October 2008.
25. Risk Assessment for Vogtle Electric Generating Plant Regarding the ILRT (Type A) Extension Request, prepared for Southern Nuclear Operating Co. by ERIN Engineering and Research, February 2003.
26. Perspectives Gained from the IPEEE Program, USNRC, NUREG-1742, April 2002.
27. Grand Gulf Nuclear Station Updated Final Safety Analysis Report (UFSAR).
28. Letter L-14-121, ML14111A291, FENOC Evaluation of the Proposed Amendment, Beaver Valley Power Station, Unit Nos. 1 and 2, April 2014.
29. Technical Letter Report ML112070867, Containment Liner Corrosion Operating Experience Summary, Revision 1, August 2011.
30. “License Amendment Request to Revise Technical Specification Section 5.5.13, ‘Primary Containment Leakage Rate Testing Program,’ for Permanent Extension of Type A and Type C Leak Rate Test Frequencies.” Clinton Power Station, Unit 1, Docket No. 50-461, License No. NPF-62, RS-16-015, January 25, 2016.
31. Armstrong, J., Simplified Level 2 Modeling Guidelines: WOG PROJECT: PA-RMSC-0088, Westinghouse, WCAP-16341-P, November 2005.
32. GGNS-94-0054, “Grand Gulf Nuclear Station Engineering Report for Individual Plant Examination of External Events,” Revision 1, November 1995.
33. ML14083A586, EPRI Evaluation, “Fleet Seismic Core Damage Frequency Estimates for Central and Eastern U.S. Nuclear Power Plants Using New Site-Specific Seismic Hazard Estimates,” March 11, 2014.
34. Generic Issue 199 (GI-199), ML100270582, September 2010, “Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern United States on Existing Plants: Safety/Risk Assessment.”
35. “The Nuclear Energy Institute - Seismic Risk Evaluations for Plants in the Central and Eastern United States,” ML14083A596, March 2014.
36. Letter to Gregory B. Jaczko, NRC Chairman, from J. Sam Armijo, ACRS, “Grand Gulf Nuclear Station, Unit 1, Extended Power Uprate License Amendment Request.”
37. GGNS-95-0041, “Grand Gulf Nuclear Station Engineering Report for Individual Plant Examination of External Events: Fire,” Revision 0, October 1996.

38. GGNS UFSAR Section 6.2, Revision 6.
39. PRA-GG-01-003, "Grand Gulf Power Station Detailed Level 2 Analysis: 2010 PSA Update," August 2010.
40. Grand Gulf Nuclear Station, ILRT-R-2008-07, "Reactor Containment Building Integrated Leakage Rate Test Report," October 18-19, 20.
41. GGNS-95-00041, "Internal Plant Examination of External Events Fire," October 1996.
42. "License Amendment Request to Extend Containment Leakage Test Frequency," Perry Nuclear Power Plant, Docket No. 50-440, License No. NPF-58, L-18-046, March 7, 2018.
43. Letter to All Power Reactor Licensees and Holders of Construction Permits in Active or Deferred Status, from the NRC, "Request for Information Pursuant to Title 10 of the Code of Federal Regulations 50.54(f) Regarding Recommendations 2.1, 2.3, and 9.3, of the Near-Term Task Force Review of Insights from the Fukushima Dai-ichi Accident," March 12, 2012.
44. Entergy letter to NRC, "Required Response 2 to March 12, 2012, Request For Information, Enclosure 2, Recommendation 2.1," Grand Gulf Nuclear Station, Unit 1 Flooding Hazard Reevaluation Report, dated March 11, 2013, ML13071A457.
45. Entergy letter to NRC, "Grand Gulf Nuclear Station Request for Additional Information Regarding Flooding Hazard," December 11, 2013, January 9, 2014, ML14014A277.
46. Entergy letter to NRC, "Focused Evaluation of External Flooding," June 27, 2017, ML17179A364.
47. Grand Gulf Nuclear Station, "Updated Final Safety Analysis Report."
48. Entergy Letter to NRC, "Grand Gulf Nuclear Station, Unit 1 – Safety Evaluation Regarding Implementation of Mitigating Strategies and Reliable Spent Fuel Pool Instrumentation Relate to Orders EA-12-049 and EA-12-051 (CAC Nos. MF0954 and MF0955)," September 27, 2016.
49. ASME/ANS RA-Sa-2009, Addenda to ASME/ANS RA-S-2008: Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications.
50. "BWROG PSA Peer Review Certification Implementation Guidelines," Revision 3, January 1997.
51. BWROG/PSA-9707, "Grand Gulf Nuclear Station PSA Peer Review Certification Report," October 1997.
52. RSC 14-15/PSA-GGNS-01-QU, "Grand Gulf Nuclear Station Probabilistic Risk Assessment Quantification, Sensitivity, and Uncertainty Analysis Work Package," Revision 0, August 2015.
53. "Grand Gulf Nuclear Station PRA Peer Review Report Using ASME/ANS PRA Standard Requirements (Internal Events and Internal Flooding at Power)," February 2016.
54. PSA-GGNS-01-FNO-RES, "Resolution of GGNS PRA Peer Review Facts and Observations," Revision 0, September 2017.
55. NEI 05-04/07-12/12-06 Appendix X, "Closeout of F&Os," March 2017 (NRC ADAMS Accession No. ML 16158A035).

56. Letter from J. Giitter (NRC) & M. Ross-Lee (NRC) to G. Krueger (NEI), "U.S. Nuclear Regulatory Commission Acceptance on Nuclear Energy Institute Appendix X to Guidance 05-04, 07-12, AND 12-13, Close-Out of Facts and Observations (F&Os)," May 3, 2017 (NRC ADAMS Accession No. ML 17079A427).

57. PSA-GGNS-01-FNO-CLOS, "GGNS PSA – Peer Review Findings Closure," Revision 0, September 2017.

58. "License Amendment Request for change to Technical Specification 5.5.13, to be extended to 15 years, Drywell Bypass Test Frequency to 15 Years and Type C Test Frequency to 75 Months," River Bend Station, Unit 1, Docket No. 50-458, License No. NPF-47, RBG-47620, October 29, 2015.

59. Regulatory Guide 1.200, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," Revision 2, March 2009.

4.0 ASSUMPTIONS AND LIMITATIONS

The following assumptions were used in the calculation:

- The GGNS Level 1 and Level 2 internal events PRA models have been peer reviewed to the requirements of Regulatory Guide 1.200 Revision 2 [Reference 59]. The models are assumed to provide representative results useful for an ILRT extension.
- The current internal events PRA model of record (Revision 4b) does not contain a full Level 2 PRA, but previous models contain a full Level 2 PRA. Where detail is needed from a Level 2 PRA, the results from the previous revisions are scaled using the current revision's total risk. It is a reasonable assumption that this scaling does not significantly affect the conclusions of this analysis.
- It is appropriate to use the GGNS internal events PRA model to effectively describe the risk change attributable to the ILRT extension. An extensive sensitivity study is done in Section 5.2.8 to show the effect of including external event models for the ILRT extension. The Seismic risk from GI-199 [Reference 34] and Fire IPEEE [Reference 41] are used for this sensitivity analysis.
- Dose results for the containment failures modeled in the PRA can be characterized by information provided in NUREG/CR-4551 [Reference 7]. They are estimated by scaling the NUREG/CR-4551 results by population differences for Grand Gulf compared to the NUREG/CR-4551 reference plant. The representative containment leakage for Class 1 sequences is $1L_a$. Class 3 accounts for increased leakage due to Type A inspection failures.
- The lowest consequence calculations (i.e., intact containment and small leakages) are based on scaling the NUREG/CR-4551 [Reference 7] results for such cases using population differences, and also based on differences in the allowable Technical Specification Leakage. Class 7 releases are based on values provided in Reference 19.
- The representative containment leakage for Class 3a sequences is $10L_a$ based on the previously approved methodology performed for Indian Point Unit 3 [Reference 8, Reference 9].
- The representative containment leakage for Class 3b sequences is $100L_a$ based on the guidance provided in EPRI Report No. 1009325, Revision 2-A (EPRI 1018243) [Reference 24].
- The Class 3b can be very conservatively categorized as LERF based on the previously approved methodology [Reference 8, Reference 9].
- The impact on population doses from containment bypass scenarios is not altered by the proposed ILRT extension, but is accounted for in the EPRI methodology as a separate entry for comparison purposes. Since the containment bypass contribution to population dose is fixed, no changes in the conclusions from this analysis will result from this separate categorization.
- The reduction in ILRT frequency does not impact the reliability of containment isolation valves to close in response to a containment isolation signal.

5.0 METHODOLOGY AND ANALYSIS

5.1 Inputs

This section summarizes the general resources available as input (Section 5.1.1) and the plant specific resources required (Section 5.1.2).

5.1.1 General Resources Available

Various industry studies on containment leakage risk assessment are briefly summarized here:

1. NUREG/CR-3539 [Reference 10]
2. NUREG/CR-4220 [Reference 11]
3. NUREG-1273 [Reference 12]
4. NUREG/CR-4330 [Reference 13]
5. EPRI TR-105189 [Reference 14]
6. NUREG-1493 [Reference 6]
7. EPRI TR-104285 [Reference 2]
8. NUREG-1150 [Reference 15] and NUREG/CR-4551 [Reference 7]
9. NEI Interim Guidance [Reference 3, Reference 20]
10. Calvert Cliffs liner corrosion analysis [Reference 5]
11. EPRI Report No. 1009325, Revision 2-A (EPRI 1018243), Appendix H [Reference 24]

This first study is applicable because it provides one basis for the threshold that could be used in the Level 2 PRA for the size of containment leakage that is considered significant and is to be included in the model. The second study is applicable because it provides a basis of the probability for significant pre-existing containment leakage at the time of a core damage accident. The third study is applicable because it is a subsequent study to NUREG/CR-4220 that undertook a more extensive evaluation of the same database. The fourth study provides an assessment of the impact of different containment leakage rates on plant risk. The fifth study provides an assessment of the impact on shutdown risk from ILRT test interval extension. The sixth study is the NRC's cost-benefit analysis of various alternative approaches regarding extending the test intervals and increasing the allowable leakage rates for containment integrated and local leak rate tests. The seventh study is an EPRI study of the impact of extending ILRT and local leak rate test (LLRT) intervals on at-power public risk. The eighth study provides an ex-plant consequence analysis for a 50-mile radius surrounding a plant that is used as the basis for the consequence analysis of the ILRT interval extension for GGNS. The ninth study includes the NEI recommended methodology (promulgated in two letters) for evaluating the risk associated with obtaining a one-time extension of the ILRT interval. The tenth study addresses the impact of age-related degradation of the containment liners on ILRT evaluations. Finally, the eleventh study builds on the previous work and includes a recommended methodology and template for evaluating the risk associated with a permanent 15-year extension of the ILRT interval.

NUREG/CR-3539 [Reference 10]

Oak Ridge National Laboratory documented a study of the impact of containment leak rates on public risk in NUREG/CR-3539. This study uses information from WASH-1400 [Reference 16] as the basis for its risk sensitivity calculations. ORNL concluded that the impact of leakage rates on LWR accident risks is relatively small.

NUREG/CR-4220 [Reference 11]

NUREG/CR-4220 is a study performed by Pacific Northwest Laboratories for the NRC in 1985. The study reviewed over two thousand LERs, ILRT reports and other related records to

calculate the unavailability of containment due to leakage.

NUREG-1273 [Reference 12]

A subsequent NRC study, NUREG-1273, performed a more extensive evaluation of the NUREG/CR-4220 database. This assessment noted that about one-third of the reported events were leakages that were immediately detected and corrected. In addition, this study noted that local leak rate tests can detect “essentially all potential degradations” of the containment isolation system.

NUREG/CR-4330 [Reference 13]

NUREG/CR-4330 is a study that examined the risk impacts associated with increasing the allowable containment leakage rates. The details of this report have no direct impact on the modeling approach of the ILRT test interval extension, as NUREG/CR-4330 focuses on leakage rate and the ILRT test interval extension study focuses on the frequency of testing intervals. However, the general conclusions of NUREG/CR-4330 are consistent with NUREG/CR-3539 and other similar containment leakage risk studies:

“…the effect of containment leakage on overall accident risk is small since risk is dominated by accident sequences that result in failure or bypass of containment.”

EPRI TR-105189 [Reference 14]

The EPRI study TR-105189 is useful to the ILRT test interval extension risk assessment because it provides insight regarding the impact of containment testing on shutdown risk. This study contains a quantitative evaluation (using the EPRI ORAM software) for two reference plants (a BWR-4 and a PWR) of the impact of extending ILRT and LLRT test intervals on shutdown risk. The conclusion from the study is that a small, but measurable, safety benefit is realized from extending the test intervals.

NUREG-1493 [Reference 6]

NUREG-1493 is the NRC’s cost-benefit analysis for proposed alternatives to reduce containment leakage testing intervals and/or relax allowable leakage rates. The NRC conclusions are consistent with other similar containment leakage risk studies:

Reduction in ILRT frequency from 3 per 10 years to 1 per 20 years results in an “imperceptible” increase in risk.

Given the insensitivity of risk to the containment leak rate and the small fraction of leak paths detected solely by Type A testing, increasing the interval between integrated leak rate tests is possible with minimal impact on public risk.

EPRI TR-104285 [Reference 2]

Extending the risk assessment impact beyond shutdown (the earlier EPRI TR-105189 study), the EPRI TR-104285 study is a quantitative evaluation of the impact of extending ILRT and LLRT test intervals on at-power public risk. This study combined IPE Level 2 models with NUREG-1150 Level 3 population dose models to perform the analysis. The study also used the approach of NUREG-1493 in calculating the increase in pre-existing leakage probability due to extending the ILRT and LLRT test intervals.

EPRI TR-104285 uses a simplified Containment Event Tree to subdivide representative core damage frequencies into eight classes of containment response to a core damage accident:

1. Containment intact and isolated
2. Containment isolation failures dependent upon the core damage accident
3. Type A (ILRT) related containment isolation failures

4. Type B (LLRT) related containment isolation failures
5. Type C (LLRT) related containment isolation failures
6. Other penetration related containment isolation failures
7. Containment failures due to core damage accident phenomena
8. Containment bypass

Consistent with the other containment leakage risk assessment studies, this study concluded:

"…the proposed CLRT (Containment Leak Rate Tests) frequency changes would have a minimal safety impact. The change in risk determined by the analyses is small in both absolute and relative terms. For example, for the PWR analyzed, the change is about 0.04 person-rem per year…"

<u>NUREG-1150 [Reference 15] and NUREG/CR-4551 [Reference 7]</u>

NUREG-1150 and the technical basis, NUREG/CR-4551, provide an ex-plant consequence analysis for a spectrum of accidents including a severe accident with the containment remaining intact (i.e., Tech Spec Leakage). This ex-plant consequence analysis is calculated for the 50-mile radial area surrounding Surry. The ex-plant calculation can be delineated to total person-rem for each identified Accident Progression Bin (APB) from NUREG/CR-4551. With the GGNS Level 2 model end-states assigned to one of the NUREG/CR-4551 APBs, it is considered adequate to represent GGNS. (The meteorology and site differences other than population are assumed not to play a significant role in this evaluation.)

<u>NEI Interim Guidance for Performing Risk Impact Assessments In Support of One-Time Extensions for Containment Integrated Leakage Rate Test Surveillance Intervals [Reference 3, Reference 20]</u>

The guidance provided in this document builds on the EPRI risk impact assessment methodology [Reference 2] and the NRC performance-based containment leakage test program [Reference 6], and considers approaches utilized in various submittals, including Indian Point 3 (and associated NRC SER) and Crystal River.

<u>Calvert Cliffs Response to Request for Additional Information Concerning the License Amendment for a One-Time Integrated Leakage Rate Test Extension [Reference 5]</u>

This submittal to the NRC describes a method for determining the change in likelihood, due to extending the ILRT, of detecting liner corrosion, and the corresponding change in risk. The methodology was developed for Calvert Cliffs in response to a request for additional information regarding how the potential leakage due to age-related degradation mechanisms was factored into the risk assessment for the ILRT one-time extension. The Calvert Cliffs analysis was performed for a concrete cylinder and dome and a concrete basemat, each with a steel liner.

<u>EPRI Report No. 1009325, Revision 2-A (EPRI 1018243), Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals [Reference 24]</u>

This report provides a generally applicable assessment of the risk involved in extension of ILRT test intervals to permanent 15-year intervals. Appendix H of this document provides guidance for performing plant-specific supplemental risk impact assessments and builds on the previous EPRI risk assessment methodology [Reference 2] and the NRC performance-based containment leakage test program [Reference 6], and considers approaches utilized in various submittals, including Indian Point 3 (and associated NRC SER) and Crystal River.

The approach included in this guidance document is used in the GGNS assessment to determine the estimated increase in risk associated with the ILRT extension. This document includes the bases for the values assigned in determining the probability of leakage for the EPRI Class 3a and 3b scenarios in this analysis, as described in Section 5.2.

5.1.2 Plant Specific Inputs

The plant-specific information used to perform the GGNS ILRT Extension Risk Assessment includes the following:

Level 1 and LERF model results [Reference 17]

Release category definitions used in the Level 2 model [Reference 18]

Population Dose calculations by release category [Reference 19, Reference 7]

ILRT results to demonstrate adequacy of the administrative and hardware issues [Reference 40]

<u>GGNS Model</u>

The Internal Events PRA Model that is used for GGNS is characteristic of the as-built plant. The GGNS PRA model of record (GGNS PRA Model Revision 4b) [Reference 17] is a linked fault tree model. The CDF is 2.58E-6/year, and the LERF is 7.74E-7/year [Reference 17]. Table 5-1 and Table 5-2 provide a summary of the Internal Events CDF and LERF results for GGNS PRA Model Revision 4b. Note: the apportioning of the sequences is performed via quantification of the Revision 4b PRA model and examining the initiating events.

The total Fire CDF is 2.74E-5/year [Reference 41]. The GI-199 Seismic CDF is 8.38E-6 [Reference 34]. Refer to Section 5.2.8 for further details on external events as they pertain to this analysis.

Table 5-1 – Internal Events CDF (GGNS PRA Model Revision 4b)

Internal Events	Frequency (per year)
LOOP	8.41E-07
LOCA	2.31E-08
ISLOCA+BOC	1.78E-09
Reactor Vessel Rupture	1.30E-08
Internal Flood	4.64E-07
Transient	1.24E-06
Total Internal Events CDF	2.58E-06

Table 5-2 – Internal Events LERF (GGNS PRA Model Revision 4b)

Internal Events	Frequency (per year)
LOOP	1.62E-07
LOCA	3.02E-10
ISLOCA+BOC	1.81E-09
Reactor Vessel Rupture	7.74E-12
Internal Flood	2.63E-07
Transient	3.47E-07
Total Internal Events LERF	7.74E-07

Release Category Definitions

Table 5-3 defines the accident classes used in the ILRT extension evaluation, which is consistent with the EPRI methodology [Reference 2]. These containment failure classifications are used in this analysis to determine the risk impact of extending the Containment Type A test interval, as described in Section 5.2 of this report.

Table 5-3 – EPRI Containment Failure Classification [Reference 2]

Class	Description
1	Containment remains intact including accident sequences that do not lead to containment failure in the long term. The release of fission products (and attendant consequences) is determined by the maximum allowable leakage rate values L_a, under Appendix J for that plant.
2	Containment isolation failures (as reported in the Individual Plant Examinations) including those accidents in which there is a failure to isolate the containment.
3	Independent (or random) isolation failures include those accidents in which the pre-existing isolation failure to seal (i.e., provide a leak-tight containment) is not dependent on the sequence in progress.
4	Independent (or random) isolation failures include those accidents in which the pre-existing isolation failure to seal is not dependent on the sequence in progress. This class is similar to Class 3 isolation failures, but is applicable to sequences involving Type B tests and their potential failures. These are the Type B-tested components that have isolated, but exhibit excessive leakage.
5	Independent (or random) isolation failures including those accidents in which the pre-existing isolation failure to seal is not dependent on the sequence in progress. This class is similar to Class 4 isolation failures, but is applicable to sequences involving Type C test and their potential failures.
6	Containment isolation failures including those leak paths covered in the plant test and maintenance requirements or verified per in-service inspection and testing (ISI/IST) program.
7	Accidents involving containment failure induced by severe accident phenomena. Changes in Appendix J testing requirements do not impact these accidents.
8	Accidents in which the containment is bypassed (either as an initial condition or induced by phenomena) are included in Class 8. Changes in Appendix J testing requirements do not impact these accidents.

5.1.3 Impact of Extension on Detection of Component Failures that Lead to Leakage (Small and Large)

The ILRT can detect a number of component failures such as liner breach, failure of certain bellows arrangements, and failure of some sealing surfaces, which can lead to leakage. The proposed ILRT test interval extension may influence the conditional probability of detecting these types of failures. To ensure that this effect is properly addressed, the EPRI Class 3 accident class, as defined in Table 5-3, is divided into two sub-classes, Class 3a and Class 3b, representing small and large leakage failures respectively.

The probability of the EPRI Class 3a and Class 3b failures is determined consistent with the EPRI Guidance [Reference 24]. For Class 3a, the probability is based on the maximum likelihood estimate of failure (arithmetic average) from the available data (i.e., 2 “small” failures in 217 tests leads to “large” failures in 217 tests (i.e., 2 / 217 = 0.0092). For Class 3b, the probability is based on the Jeffreys non-informative prior (i.e., 0.5 / 218 = 0.0023).

In a follow-up letter [Reference 20] to their ILRT guidance document [Reference 3], NEI issued additional information concerning the potential that the calculated delta LERF values for several plants may fall above the “very small change” guidelines of the NRC Regulatory Guide 1.174 [Reference 4]. This additional NEI information includes a discussion of conservatisms in the quantitative guidance for ΔLERF. NEI describes ways to demonstrate that, using plant-specific calculations, the ΔLERF is smaller than that calculated by the simplified method.

The supplemental information states:
The methodology employed for determining LERF (Class 3b frequency) involves conservatively multiplying the CDF by the failure probability for this class (3b) of accident. This was done for simplicity and to maintain conservatism. However, some plant-specific accident classes leading to core damage are likely to include individual sequences that either may already (independently) cause a LERF or could never cause a LERF, and are thus not associated with a postulated large Type A containment leakage path (LERF). These contributors can be removed from Class 3b in the evaluation of LERF by multiplying the Class 3b probability by only that portion of CDF that may be impacted by Type A leakage.

The application of this additional guidance to the analysis for GGNS, as detailed in Section 5.2, involves subtracting the LERF from the CDF that is applied to Class 3b. To be consistent, the same change is made to the Class 3a CDF, even though these events are not considered LERF.

Consistent with the NEI Guidance [Reference 3], the change in the leak detection probability can be estimated by comparing the average time that a leak could exist without detection. For example, the average time that a leak could go undetected with a three-year test interval is 1.5 years (3 years / 2), and the average time that a leak could exist without detection for a ten-year interval is 5 years (10 years / 2). This change would lead to a non-detection probability that is a factor of 3.33 (5.0/1.5) higher for the probability of a leak that is detectable only by ILRT testing. Correspondingly, an extension of the ILRT interval to 15 years can be estimated to lead to a factor of 5 ((15/2)/1.5) increase in the non-detection probability of a leak.

It should be noted that using the methodology discussed above is very conservative compared to previous submittals (e.g., the IP3 request for a one-time ILRT extension that was approved by the NRC [Reference 9]) because it does not factor in the possibility that the failures could be detected by other tests (e.g., the Type B local leak rate tests that will still occur). Eliminating this possibility conservatively over-estimates the factor increases attributable to the ILRT extension.

5.2 Analysis

The application of the approach based on the guidance contained in EPRI 1018243 [Reference 24] and previous risk assessment submittals on this subject [References 5, 8, 21, 22, and 23] have led to the following results. The results are displayed according to the eight accident classes defined in the EPRI report, as described in Table 5-4.

The analysis performed examined GGNS-specific accident sequences in which the containment remains intact or the containment is impaired. Specifically, the breakdown of the severe accidents, contributing to risk, was considered in the following manner:

- Core damage sequences in which the containment remains intact initially and in the long term (EPRI 1018243, Class 1 sequences [Reference 24]).
- Core damage sequences in which containment integrity is impaired due to random isolation failures of plant components other than those associated with Type B or Type C test components. For example, liner breach or bellow leakage (EPRI 1018243, Class 3 sequences [Reference 24]).
- Accident sequences involving containment bypassed (EPRI 1009325, Class 8 sequences [Reference 24]), large containment isolation failures (EPRI 1018243, Class 2 sequences [Reference 24]), and small containment isolation “failure-to-seal” events (EPRI 1018243, Class 4 and 5 sequences [Reference 24]) are accounted for in this evaluation as part of the baseline risk profile. However, they are not affected by the ILRT frequency change.

- Class 4 and 5 sequences are impacted by changes in Type B and C test intervals; therefore, changes in the Type A test interval do not impact these sequences.

Table 5-4 – EPRI Accident Class Definitions

Accident Classes (Containment Release Type)	Description
1	No Containment Failure
2	Large Isolation Failures (Failure to Close)
3a	Small Isolation Failures (Liner Breach)
3b	Large Isolation Failures (Liner Breach)
4	Small Isolation Failures (Failure to Seal – Type B)
5	Small Isolation Failures (Failure to Seal – Type C)
6	Other Isolation Failures (e.g., Dependent Failures)
7	Failures Induced by Phenomena (Early and Late)
8	Bypass (Interfacing System LOCA)
CDF	All CET End States (Including Very Low and No Release)

The steps taken to perform this risk assessment evaluation are as follows:

Step 1 - Quantify the baseline risk in terms of frequency per reactor year for each of the accident classes presented in Table 5-4.

Step 2 - Develop plant-specific person-rem dose (population dose) per reactor year for each of the eight accident classes.

Step 3 - Evaluate risk impact of extending Type A test interval from 3 in 10 years to 1 in 15 years and 1 in 10 years to 1 in 15 years.

Step 4 - Determine the change in risk in terms of Large Early Release Frequency (LERF) in accordance with RG 1.174 [Reference 4].

Step 5 - Determine the impact on the Conditional Containment Failure Probability (CCFP).

5.2.1 Step 1 – Quantify the Baseline Risk in Terms of Frequency per Reactor Year

As previously described, the extension of the Type A interval does not influence those accident progressions that involve large containment isolation failures, Type B or Type C testing, or containment failure induced by severe accident phenomena.

For the assessment of ILRT impacts on the risk profile, the potential for pre-existing leaks is included in the model (these events are represented by the Class 3 sequences in EPRI 1018243 [Reference 24].) The question on containment integrity was modified to include the probability of a liner breach or bellows failure (due to excessive leakage) at the time of core damage. Two failure modes were considered for the Class 3 sequences. These are Class 3a (small breach) and Class 3b (large breach).

The frequencies for the severe accident classes defined in Table 5-4 were developed for GGNS by first determining the frequencies for Classes 1, 2, 7, and 8. Table 5-5 presents the grouping of the release categories in EPRI Classes. Table 5-6 provides a summary of the accident sequence frequencies that can lead to radionuclide release to the public and have been derived consistent with the definitions of accident classes defined in EPRI TR-104285 [Reference 2], the NEI Interim Guidance [Reference 3], and guidance provided in EPRI Report No. 1018243 [Reference 24]. Adjustments were made to the Class 3b and hence Class 1 frequencies to

account for the impact of undetected corrosion of the steel liner per the methodology described in Section 5.2.6. Note: calculations were performed with more digits than shown in this section. Therefore, minor differences may occur if the calculations in these sections are followed explicitly.

Class 3 Sequences. This group consists of all core damage accident progression bins for which a pre-existing leakage in the containment structure (e.g., containment liner) exists that can only be detected by performing a Type A ILRT. The probability of leakage detectable by a Type A ILRT is calculated to determine the impact of extending the testing interval. The Class 3 calculation is divided into two classes: Class 3a is defined as a small liner breach (L_a < leakage < $10L_a$), and Class 3b is defined as a large liner breach ($10L_a$ < leakage < $100L_a$).

Data reported in EPRI 1018243 [Reference 24] states that two events could have been detected only during the performance of an ILRT and thus impact risk due to change in ILRT frequency. There were a total of 217 successful ILRTs during this data collection period. Therefore, the probability of leakage is determined for Class 3a as shown in the following equation:

$$P_{class3a} = \frac{2}{217} = 0.0092$$

Multiplying the CDF by the probability of a Class 3a leak yields the Class 3a frequency contribution in accordance with guidance provided in Reference 24. As described in Section 5.1.3, additional consideration is made to not apply failure probabilities on those cases that are already LERF scenarios. Therefore, these LERF contributions from CDF are removed. The frequency of a Class 3a failure is calculated by the following equation:

$$Freq_{class3a} = P_{class3a} * (CDF - LERF) = \frac{2}{217} * (2.58\text{E-}6 - 7.74\text{E-}7) = 1.66\text{E-}8$$

In the database of 217 ILRTs, there are zero containment leakage events that could result in a large early release. Therefore, the Jeffreys non-informative prior is used to estimate a failure rate and is illustrated in the following equations:

$$\text{Jeffreys Failure Probability} = \frac{Number\ of\ Failures + 1/2}{Number\ of\ Tests + 1}$$

$$P_{class3b} = \frac{0 + 1/2}{217 + 1} = 0.0023$$

The frequency of a Class 3b failure is calculated by the following equation:

$$Freq_{class3b} = P_{class3b} * (CDF - LERF) = \frac{.5}{218} * (2.58\text{E-}6 - 7.74\text{E-}7) = 4.14\text{E-}09$$

For this analysis, the associated containment leakage for Class 3a is $10L_a$ and for Class 3b is $100L_a$. These assignments are consistent with the guidance provided in Reference 24.

Class 1 Sequences. This group consists of all core damage accident progression bins for which the containment remains intact (modeled as Technical Specification Leakage). The No Containment Failure (NCF) value given in Reference 19 is 8.73E-7. This value is adjusted from Table E.1-8 of Reference 19. The total CDF provided in Table E.1-8 of Reference 19 is 2.05E-6, which is slightly less than the CDF of 2.58E-6 provided in Reference 17. The scaled NCF is 1.10E-6. It is assumed that since similar models are used in References 17 and 19 and the scaling is a relatively small change, the CDF scaling provides reasonable results. The frequency per year is then calculated by subtracting the EPRI Class 3a and 3b (to preserve total CDF), calculated below:

$$Freq_{class1} = Freq_{Intact} - (Freq_{class3a} + Freq_{class3b})$$

Class 2 Sequences. This group consists of core damage accident progression bins with large containment isolation failures. Flag CIS-FLAG was added to the model to calculate the Class 2 contribution to LERF. The Fussell-Vesely (FV) of the flag is 1.92E-2, which is multiplied by the total LERF for a Class 2 contribution of 1.49E-8.

Class 4 Sequences. This group consists of all core damage accident progression bins for which containment isolation failure-to-seal of Type B test components occurs. Because these failures are detected by Type B tests which are unaffected by the Type A ILRT, this group is not evaluated any further in the analysis, consistent with approved methodology.

Class 5 Sequences. This group consists of all core damage accident progression bins for which a containment isolation failure-to-seal of Type C test components occurs. Because the failures are detected by Type C tests which are unaffected by the Type A ILRT, this group is not evaluated any further in this analysis, consistent with approved methodology.

Class 6 Sequences. These are sequences that involve core damage accident progression bins for which a failure-to-seal containment leakage due to failure to isolate the containment occurs. These sequences are dominated by misalignment of containment isolation valves following a test/maintenance evolution. All other failure modes are bounded by the Class 2 assumptions. This accident class is also not evaluated further.

Class 7 Sequences. This group consists of all core damage accident progression bins in which containment failure is induced by severe accident phenomena (e.g., overpressure). These accident scenarios could result in varying quantities of release in varying time frames. Any sequence that does not categorize as Classes 1, 2, or 8 is assigned to this category. For this analysis, the EPRI Accident Class 7 base frequency is listed in Table 5-5.

Class 8 Sequences. This group consists of risk from ISLOCA or Break Outside Containment (BOC) sequences. For this analysis, the total frequency is listed in Table 5-1 and Table 5-5.

Table 5-5 – Release Category Frequencies

Containment End State	EPRI Category	Frequency (/yr)
Intact Containment	1	1.10E-06
Large Isolation Failure	2	1.49E-08
Failures Induced by Phenomena	7	1.46E-06
ISLOCA + BOC	8	1.78E-09

Table 5-6 – Baseline Risk Profile

Class	Description	Frequency (/yr)
1	No containment failure	1.08E-06[2]
2	Large containment isolation failures	1.49E-08
3a	Small isolation failures (liner breach)	1.66E-08
3b	Large isolation failures (liner breach)	4.14E-09
4	Small isolation failures - failure to seal (type B)	ε[1]
5	Small isolation failures - failure to seal (type C)	ε[1]
6	Containment isolation failures (dependent failure, personnel errors)	ε[1]
7	Severe accident phenomena induced failure (early and late)	1.46E-06
8	Containment bypass	1.78E-09
	Total	2.58E-06

1. ε represents a probabilistically insignificant value or a Class that is unaffected by the Type A ILRT.
2. The Class 3a and 3b frequencies are subtracted from Class 1 to preserve total CDF.

5.2.2 Step 2 – Develop Plant-Specific Person-Rem Dose (Population Dose)

Plant-specific release analyses were performed to estimate the person-rem doses to the population within a 50-mile radius from the plant. Reference 19 provides the population dose for Class 7 releases based on timing (early, intermediate, or late) and magnitude (low-low, low, medium, or high). Early releases are categorized as occurring before four hours (after declaration of General Emergency); intermediate releases are categorized as occurring between four and 24 hours; and late releases are categorized as occurring after 24 hours [Reference 19]. The Class 7 dose is a weighted average of the doses for each release category.

The population dose for Classes 1, 2, and 8 are calculated using the methodology of scaling Peach Bottom population doses to GGNS [Reference 7]. The adjustment factor for reactor power level (AF_{power}) is defined as the ratio of the power level at GGNS (PLG) [Section 1.1.7 of Reference 27] to that at Peach Bottom Unit 2 (PLP) [Reference 7]. This adjustment factor is calculated as follows:

$$AF_{power} = PLG / PLP = 4408 / 3293 = 1.339$$

The adjustment factor for technical specification (TS) allowed containment leakage is defined as the ratio of the containment leakage at Grand Gulf (LRG) to that at Peach Bottom Unit 2 (LRP). This adjustment factor is calculated as follows:

$$AF_{leakage} = LRG / LRP$$

Since the leakage rates are in terms of the containment volume, the ratio of containment volumes is needed to relate the leakage rates. The TS maximum allowed containment leakage at GGNS (TS_{GG}) is 0.385%/day [Section 6.2 of Reference 27]; the containment free volume at GGNS (VOL_{GG}) is 1,400,000 ft^3 [Section 6.2.1.1.4 of Reference 27]. The TS maximum allowed containment leakage at Peach Bottom Unit 2 (TS_{PB}) is 0.5%/day [Reference 7]; the containment free volume at Peach Bottom Unit 2 (VOL_{PB}) is 307,000 ft^3 [Reference 7]. Therefore,

$$LRG = TS_{GG} * VOL_{GG}$$

$$LRP = TS_{PB} * VOL_{PB}$$

$$AF_{leakage} = (0.385 * 1400000) / (0.5 * 307000) = 3.511$$

The adjustment factor for population ($AF_{Population}$) is defined as the ratio of the population within 50-mile radius of GGNS (POPG) [Reference 19] to that of Peach Bottom Unit 2 (POPP) [Reference 7]. The 2044 population surrounding GGNS was estimated as 359,039 [Section E.1.5.2.1 of Reference 19]. This adjustment factor is calculated as follows:

$$AF_{Population} = POPG / POPP = 359039 / 3.02E{+}6 = 0.119$$

Consequences dependent on the INTACT TS Leakage (collapsed accident progression bins 8 and 10) are calculated by combining the factors as follows:

$$AF_{INTACT} = AF_{power} * AF_{Leakage} * AF_{Population} = 1.339 * 3.511 * 0.119 = 0.559$$

Since the other categories are not dependent on the TS Leakage, the adjustment factor (AF) is calculated by combining the factors as follows:

$$AF = AF_{power} * AF_{Population} = 1.339 * 0.119 = 0.159$$

The population dose data in NUREG/CR-4551 for Peach Bottom Unit 2 [Reference 7] is reported in ten distinct collapsed accident progression bins (CAPBs). For this ILRT extension application, CAPB8 and CAPB10 are categorized in EPRI Accident Class 1; CAPB3 is categorized in EPRI Accident Class 2; and CAPB7 is categorized in EPRI Accident Class 8. Based on the above adjustment factors and the 50-mile population dose (person-rem) for each CAPB considered in the NUREG/CR-4551 Peach Bottom Unit 2 study, the GGNS population doses (GPD) for Classes 2 and 8 are calculated as follows:

$$GPD_{Class1} = AF_{INTACT} * PD_{CAPB8} + AF_{INTACT} * PD_{CAPB10} = 0.559 * 4.94E{+}3 + 0.559 * 0 = 2.76E{+}3$$

$$GPD_{Class2} = AF * PD_{CAPB3} = 0.159 * 2.97E{+}6 = 4.73E{+}5$$

$$GPD_{Class8} = AF * PD_{CAPB7} = 0.159 * 1.95E{+}6 = 3.10E{+}5$$

Table 5-7 provides a correlation of GGNS population dose to EPRI Accident Class. Table 5-8 provides population dose for each EPRI accident class.

The population dose for EPRI Accident Classes 3a and 3b were calculated based on the guidance provided in EPRI 1018243 [Reference 24] as follows:

$$EPRI\ Class\ 3a\ Population\ Dose = 10 * 2.76E{+}3 = 2.76E{+}4$$

$$EPRI\ Class\ 3b\ Population\ Dose = 100 * 2.76E{+}3 = 2.76E{+}5$$

Table 5-7 – Mapping of Population Dose to EPRI Accident Class

EPRI Category	Frequency (/yr)	Dose (person-rem)
Class 1	1.82E-06	2.76E+03
Class 2	2.48E-09	4.73E+05
Class 6	N/A – Included in Class 2	
Class 7	2.45E-06	4.12E+05
Class 8	9.67E-10	3.10E+05

Table 5-8 – Baseline Population Doses

Class	Description	Population Dose (person-rem)
1	No containment failure	2.76E+03
2	Large containment isolation failures	4.73E+05
3a	Small isolation failures (liner breach)	2.76E+04[1]
3b	Large isolation failures (liner breach)	2.76E+05[2]
4	Small isolation failures - failure to seal (type B)	N/A
5	Small isolation failures - failure to seal (type C)	N/A
6	Containment isolation failures (dependent failure, personnel errors)	N/A
7	Severe accident phenomena induced failure (early and late)	4.12E+05
8	Containment bypass	3.10E+05

1. $10*L_a$
2. $100*L_a$

5.2.3 Step 3 – Evaluate Risk Impact of Extending Type A Test Interval from 10 to 15 Years

The next step is to evaluate the risk impact of extending the test interval from its current 10-year interval to a 15-year interval. To do this, an evaluation must first be made of the risk associated with the 10-year interval, since the base case applies to 3-year interval (i.e., a simplified representation of a 3-to-10 interval).

<u>Risk Impact Due to 10-Year Test Interval</u>

As previously stated, Type A tests impact only Class 3 sequences. For Class 3 sequences, the release magnitude is not impacted by the change in test interval (a small or large breach remains the same, even though the probability of not detecting the breach increases). Thus, only the frequency of Class 3a and Class 3b sequences is impacted. The risk contribution is changed based on the NEI guidance as described in Section 5.1.3 by a factor of 10/3 compared to the base case values. The Class 3a and 3b frequencies are calculated as follows:

$$Freq_{Class3a10yr} = \frac{10}{3} * \frac{2}{217} * (CDF - LERF) = \frac{10}{3} * \frac{2}{217} * 1.81\text{E-}6 = 5.55\text{E-}8$$

$$Freq_{Class3b10yr} = \frac{10}{3} * \frac{.5}{218} * (CDF - LERF) = \frac{10}{3} * \frac{.5}{218} * 1.81\text{E-}6 = 1.38\text{E-}8$$

The results of the calculation for a 10-year interval are presented in Table 5-9.

Table 5-9 – Risk Profile for Once in 10 Year ILRT

Class	Description	Frequency (/yr)	Contribution (%)	Population Dose (person-rem)	Population Dose Rate (person-rem/yr)
1	No containment failure[2]	1.03E-06	39.90%	2.76E+03	2.84E-03
2	Large containment isolation failures	1.49E-08	0.58%	4.73E+05	7.02E-03
3a	Small isolation failures (liner breach)	5.55E-08	2.15%	2.76E+04	1.53E-03
3b	Large isolation failures (liner breach)	1.38E-08	0.54%	2.76E+05	3.81E-03
4	Small isolation failures - failure to seal (type B)	ε[1]	ε[1]	ε[1]	ε[1]
5	Small isolation failures - failure to seal (type C)	ε[1]	ε[1]	ε[1]	ε[1]
6	Containment isolation failures (dependent failure, personnel errors)	ε[1]	ε[1]	ε[1]	ε[1]
7	Severe accident phenomena induced failure (early and late)	1.46E-06	56.77%	4.12E+05	6.04E-01
8	Containment bypass	1.78E-09	0.07%	3.10E+05	5.52E-04
	Total	**2.58E-06**			**6.20E-01**

1. ε represents a probabilistically insignificant value or a Class that is unaffected by the Type A ILRT.
2. The Class 1 frequency is reduced by the frequency of Class 3a and Class 3b in order to preserve total CDF.

Risk Impact Due to 15-Year Test Interval

The risk contribution for a 15-year interval is calculated in a manner similar to the 10-year interval. The difference is in the increase in probability of leakage in Classes 3a and 3b. For this case, the value used in the analysis is a factor of 5 compared to the 3-year interval value, as described in Section 5.1.3. The Class 3a and 3b frequencies are calculated as follows:

$$Freq_{Class3a15yr} = \frac{15}{3} * \frac{2}{217} * (CDF - LERF) = 5 * \frac{2}{217} * 1.81\text{E-}6 = 8.32\text{E-}8$$

$$Freq_{Class3b15yr} = \frac{15}{3} * \frac{.5}{218} * (CDF - LERF) = 5 * \frac{.5}{218} * 1.81\text{E-}6 = 2.07\text{E-}8$$

The results of the calculation for a 15-year interval are presented in Table 5-10.

Table 5-10 – Risk Profile for Once in 15 Year ILRT

Class	Description	Frequency (/yr)	Contribution (%)	Population Dose (person-rem)	Population Dose Rate (person-rem/yr)
1	No containment failure[2]	9.95E-07	38.56%	2.76E+03	2.75E-03
2	Large containment isolation failures	1.49E-08	0.58%	4.73E+05	7.02E-03
3a	Small isolation failures (liner breach)	8.32E-08	3.23%	2.76E+04	2.30E-03
3b	Large isolation failures (liner breach)	2.07E-08	0.80%	2.76E+05	5.72E-03
4	Small isolation failures - failure to seal (type B)	ε[1]	ε[1]	ε[1]	ε[1]
5	Small isolation failures - failure to seal (type C)	ε[1]	ε[1]	ε[1]	ε[1]
6	Containment isolation failures (dependent failure, personnel errors)	ε[1]	ε[1]	ε[1]	ε[1]
7	Severe accident phenomena induced failure (early and late)	1.46E-06	56.77%	4.12E+05	6.04E-01
8	Containment bypass	1.78E-09	0.07%	3.10E+05	5.52E-04
	Total	**2.58E-06**			**6.22E-01**

1. ε represents a probabilistically insignificant value or a Class that is unaffected by the Type A ILRT .
2. The Class 1 frequency is reduced by the frequency of Class 3a and Class 3b in order to preserve total CDF.

5.2.4 Step 4 – Determine the Change in Risk in Terms of LERF

The risk increase associated with extending the ILRT interval involves the potential that a core damage event that normally would result in only a small radioactive release from an intact containment could, in fact, result in a larger release due to the increase in probability of failure to detect a pre-existing leak. With strict adherence to the EPRI guidance, 100% of the Class 3b contribution would be considered LERF.

Regulatory Guide 1.174 [Reference 4] provides guidance for determining the risk impact of plant-specific changes to the licensing basis. RG 1.174 [Reference 4] defines “very small” changes in risk as resulting in increases of CDF less than 10^{-6}/year and increases in LERF less than 10^{-7}/year, and small changes in LERF as less than 10^{-6}/year. Since containment accident pressure is not required in support of ECCS performance to mitigate design basis accidents at GGNS [Reference 36], the ILRT extension does not impact CDF. Therefore, the relevant risk-impact metric is LERF.

For GGNS, 100% of the frequency of Class 3b sequences can be used as a very conservative first-order estimate to approximate the potential increase in LERF from the ILRT interval extension (consistent with the EPRI guidance methodology). Based on a 10-year test interval from Table 5-9, the Class 3b frequency is 1.38E-8/year; based on a 15-year test interval from Table 5-10, the Class 3b frequency is 2.07E-8/year. Thus, the increase in the overall probability of LERF due to Class 3b sequences that is due to increasing the ILRT test interval from 3 to 15 years is 1.66E-8/year. Similarly, the increase due to increasing the interval from 10 to 15 years is 6.90E-9/year. As can be seen, even with the conservatisms included in the evaluation (per

the EPRI methodology), the estimated change in LERF is within the criteria for a “very small" change when comparing the 15-year results to the current 10-year requirement and the original 3-year requirement [Reference 4]. Table 5-11 summarizes these results.

Table 5-11 – Impact on LERF due to Extended Type A Testing Intervals

ILRT Inspection Interval	3 Years (baseline)	10 Years	15 Years
Class 3b (Type A LERF)	4.14E-09	1.38E-08	2.07E-08
ΔLERF (3 year baseline)		9.67E-09	1.66E-08
ΔLERF (10 year baseline)			6.90E-09

EPRI 1018243 [Reference 24] states that a “small” population dose is defined as an increase of ≤ 1.0 person-rem per year, or ≤ 1% of the total population dose, whichever is less restrictive for the risk impact assessment of the extended ILRT intervals. As shown in Table 5-12, the results of this calculation meet the dose rate criteria.

Table 5-12 – Impact on Dose Rate due to Extended Type A and DBLT Testing Intervals

ILRT and DBLT Inspection Interval	10 Years	15 Years
ΔDose Rate (3 year baseline)	3.61E-03	6.18E-03
ΔDose Rate (10 year baseline)		2.58E-03
%ΔDose Rate (3 year baseline)	0.585%	1.003%
%ΔDose Rate (10 year baseline)		0.642%

5.2.5 Step 5 – Determine the Impact on the Conditional Containment Failure Probability

Another parameter that the NRC guidance in RG 1.174 [Reference 4] states can provide input into the decision-making process is the change in the conditional containment failure probability (CCFP). The CCFP is defined as the probability of containment failure given the occurrence of an accident. This probability can be expressed using the following equation:

$$CCFP = 1 - \frac{f(ncf)}{CDF}$$

where *f*(ncf) is the frequency of those sequences that do not result in containment failure; this frequency is determined by summing the Class 1 and Class 3a results [Reference 24]. Table 5-13 shows the steps and results of this calculation.

Table 5-13 – Impact on CCFP due to Extended Type A Testing Intervals

ILRT Inspection Interval	3 Years (baseline)	10 Years	15 Years
f(ncf) (/yr)	1.09E-06	1.08E-06	1.08E-06
f(ncf)/CDF	0.424	0.421	0.418
CCFP	0.576	0.579	0.582
ΔCCFP (3 year baseline)		0.375%	0.642%
ΔCCFP (10 year baseline)			0.268%

As stated in Section 2.0, a change in the CCFP of up to 1.5% is assumed to be small. The

increase in the CCFP from the 3 in 10 year interval to 1 in 15 year interval is 0.642%. Therefore, this increase is judged to be small.

5.2.6 Impact of Extension on Detection of Steel Liner Corrosion that Leads to Leakage

An estimate of the likelihood and risk implications of corrosion-induced leakage of the steel liners occurring and going undetected during the extended test interval is evaluated using a methodology similar to the Calvert Cliffs liner corrosion analysis [Reference 5]. The Calvert Cliffs analysis was performed for a concrete cylinder and dome and a concrete basemat, each with a steel liner.

The following approach is used to determine the change in likelihood, due to extending the ILRT, of detecting corrosion of the containment steel liner [Section 5.1.5.1 of Reference 24]. This likelihood is then used to determine the resulting change in risk. Consistent with the Calvert Cliffs analysis, the following issues are addressed:

- Differences between the containment basemat and the containment cylinder and dome
- The historical steel liner flaw likelihood due to concealed corrosion
- The impact of aging
- The corrosion leakage dependency on containment pressure
- The likelihood that visual inspections will be effective at detecting a flaw

<u>Assumptions</u>

- Based on a review of industry events, an Oyster Creek incident is assumed to be applicable to GGNS for a concealed shell failure in the floor. In the Calvert Cliffs analysis, this event was assumed not to be applicable and a half failure was assumed for basemat concealed liner corrosion due to the lack of identified failures (See Table 5-14, Step 1).
- The two corrosion events used to estimate the liner flaw probability in the Calvert Cliffs previous analysis are assumed to still be applicable.
- Consistent with the Calvert Cliffs analysis, the estimated historical flaw probability data period is also limited to 5.5 years to reflect the years since September 1996 when 10 CFR 50.55a started requiring visual inspection. Additional success data was not used to limit the aging impact of this corrosion issue, even though inspections were being performed prior to this date (and have been performed since the time frame of the Calvert Cliffs analysis) (See Table 5-14, Step 1).
- Consistent with the Calvert Cliffs analysis, the steel liner flaw likelihood is assumed to double every five years. This is based solely on judgment and is included in this analysis to address the increased likelihood of corrosion as the steel liner ages (See Table 5-14, Steps 2 and 3). Sensitivity studies are included that address doubling this rate every ten years and every two years.
- In the Calvert Cliffs analysis, the likelihood of the containment atmosphere reaching the outside atmosphere, given that a liner flaw exists, was estimated as 1.1% for the cylinder and dome, and 0.11% (10% of the cylinder failure probability) for the basemat. These values were determined from an assessment of the probability versus containment pressure. For GGNS, the containment design pressure is 56 psig [Reference 27]. Probabilities of 1% for the cylinder and dome, and 0.1% for the basemat are used in this analysis, and sensitivity studies are included in Section 5.3.2 (See Table 5-14, Step 4).
- Consistent with the Calvert Cliffs analysis, the likelihood of leakage escape (due to crack formation) in the basemat region is considered to be less likely than the containment cylinder and dome region (See Table 5-14, Step 4).

- Consistent with the Calvert Cliffs analysis, a 5% visual inspection detection failure likelihood given the flaw is visible and a total detection failure likelihood of 10% is used. To date, all liner corrosion events have been detected through visual inspection (See Table 5-14, Step 5).
- Consistent with the Calvert Cliffs analysis, all non-detectable containment failures are assumed to result in early releases. This approach avoids a detailed analysis of containment failure timing and operator recovery actions.

Table 5-14 – Steel Liner Corrosion Base Case

Step	Description	Containment Cylinder and Dome (85%)	Containment Basemat (15%)
1	Historical liner flaw likelihood Failure data: containment location specific Success data: based on 70 steel-lined containments and 5.5 years since the 10CFR 50.55a requirements of periodic visual inspections of containment surfaces	Events: 2 (Brunswick 2 and North Anna 2) 2 / (70 x 5.5) = 5.19E-03	Events: 1 1 / (70 x 5.5) = 2.60E-03
2	Aged adjusted liner flaw likelihood During the 15-year interval, assume failure rate doubles every five years (14.9% increase per year). The average for the 5th to 10th year set to the historical failure rate.	Year / Failure rate 1 / 2.05E-03 average 5-10 / 5.19E-03 15 / 1.43E-02 15 year average = 6.44E-03	Year / Failure rate 1 / 1.03E-03 average 5-10 / 2.60E-03 15 / 7.14E-03 15 year average = 3.22E-03
3	Increase in flaw likelihood between 3 and 15 years Uses aged adjusted liner flaw likelihood (Step 2), assuming failure rate doubles every five years.	0.71% (1 to 3 years) 4.14% (1 to 10 years) 9.66% (1 to 15 years)	0.36% (1 to 3 years) 2.07% (1 to 10 years) 4.83% (1 to 15 years)
4	Likelihood of breach in containment given liner flaw	1%	0.1%
5	Visual inspection detection failure likelihood	10% 5% failure to identify visual flaws plus 5% likelihood that the flaw is not visible (not through-cylinder but could be detected by ILRT). All events have been detected through visual inspection. 5% visible failure detection is a conservative assumption.	100% Cannot be visually inspected
6	Likelihood of non-detected containment leakage (Steps 3 x 4 x 5)	0.00071% (3 years) 0.71% x 1% x 10% 0.00414% (10 years) 4.14% x 1% x 10% 0.00966% (15 years) 9.66% x 1% x 10%	0.00036% (3 years) 0.36% x 0.1% x 100% 0.00207% (10 years) 2.07% x 0.1% x 100% 0.00483% (15 years) 4.83% x 0.1% x 100%

The total likelihood of the corrosion-induced, non-detected containment leakage is the sum of Step 6 for the containment cylinder and dome, and the containment basemat, as summarized

below for GGNS.

Table 5-15 – Total Likelihood on Non-Detected Containment Leakage Due to Corrosion for GGNS

Description
At 3 years: 0.00071% + 0.00036% = 0.00107%
At 10 years: 0.00414% + 0.00207% = 0.00621%
At 15 years: 0.00966% + 0.00483% = 0.01449%

The above factors are applied to those core damage accidents that are not already independently LERF or that could never result in LERF.

The two corrosion events that were initiated from the non-visible (backside) portion of the containment liner used to estimate the liner flaw probability in the Calvert Cliffs analysis are assumed to be applicable to this containment analysis. These events, one at North Anna Unit 2 (September 1999) caused by timber embedded in the concrete immediately behind the containment liner, and one at Brunswick Unit 2 (April 1999) caused by a cloth work glove embedded in the concrete next to the liner, were initiated from the nonvisible (backside) portion of the containment liner. A search of the NRC website LER database identified two additional events have occurred since the Calvert Cliffs analysis was performed. In January 2000, a 3/16-inch circular through-liner hole was found at Cook Nuclear Plant Unit 2 caused by a wooden brush handle embedded immediately behind the containment liner. The other event occurred in April 2009, where a through-liner hole approximately 3/8-inch by 1-inch in size was identified in the Beaver Valley Power Station Unit 1 (BVPS-1) containment liner caused by pitting originating from the concrete side due to a piece of wood that was left behind during the original construction that came in contact with the steel liner. Two other containment liner through-wall hole events occurred at Turkey Point Units 3 and 4 in October 2010 and November 2006, respectively. However, these events originated from the visible side caused by the failure of the coating system, which was not designed for periodic immersion service, and are not considered to be applicable to this analysis. More recently, in October 2013, some through-wall containment liner holes were identified at BVPS-1, with a combined total area of approximately 0.395 square inches. The cause of these through-wall liner holes was attributed to corrosion originating from the outside concrete surface due to the presence of rayon fiber foreign material that was left behind during the original construction and was contacting the steel liner [Reference 28]. For risk evaluation purposes, these five total corrosion events occurring in 66 operating plants with steel containment liners over a 17.1 year period from September 1996 to October 4, 2013 (i.e., 5/(66*17.1) = 4.43E-03) are bounded by the estimated historical flaw probability based on the two events in the 5.5 year period of the Calvert Cliffs analysis (i.e., 2/(70*5.5) = 5.19E-03) incorporated in the EPRI guidance.

5.2.7 Potential Impact from External Events Contribution

An assessment of the impact of external events is performed. The primary purpose for this investigation is the determination of the total LERF following an increase in the ILRT testing interval from 3 in 10 years to 1 in 15 years.

The GGNS IPEEE calculated a fire CDF of 2.74E-5 [Reference 41], and these results are considered reasonable for this analysis. Since no LERF value is directly provided, the fire LERF is estimated as 10% of the fire CDF to obtain a fire LERF of 2.74E-6. The fire LERF can also be estimated using the ratio of the internal events LERF to the CDF; however, for GGNS this ratio is 30%, which is unusually high and using this to estimate the fire LERF is overly conservative for the total LERF.

In support of the 10% fire LERF to CDF ratio, the ratios from the other Mark III containment plants and the ratio from the GGNS Severe Accident Mitigation Alternatives (SAMA) are provided below. As shown, the LERF/CDF ratio is typically about 5%.

Table 5-16 – Comparison of LERF/CDF Ratio for Mark III Plants

Plant	CDF	LERF	LERF/CDF	Reference
Clinton	2.13E-06	1.16E-07	5.4%	Reference 30, Attachment 4, Section 4.2
River Bend	2.60E-06	2.48E-08	1.0%	Reference 58, Attachment 3, Section 4.2
Perry	3.02E-06	1.39E-07	4.6%	Reference 42, Attachment 2, Section 5.1.2
Grand Gulf (SAMA)	2.91E-06	1.48E-07	5.1%	Reference 19, Section E.1.4, 2010 EPU

Additionally, Reference 18 discusses some conservative LERF assumptions. First, all accident sequences resulting in core damage are binned as short-term failures. Secondly, the recovery of short-term and long-term injection systems is not considered for in-vessel arrest of core melt.

Therefore, based on the data provided in Table 5-16 and the conservative nature of the LERF modeling, assuming a 10% ratio to estimate the fire LERF is more realistic and likely still bounding for the delta and total LERF external events evaluation.

$$\mathrm{LERF_{Fire}} \approx \mathrm{CDF_{Fire}} * 0.1 = 2.74\text{E-}5 * 0.1 = 2.74\text{E-}6$$

As described in Section 5.1.3, consideration is made to not apply failure probabilities on those cases that are already LERF scenarios. Therefore, LERF contributions from CDF are removed from the calculation of Class3b. The following shows the calculation for Class 3b:

$$Freq_{class3b} = P_{class3b} * (CDF - LERF) = \frac{0.5}{218} * (2.74E\text{-}5 - 2.74E\text{-}6) = 5.66\text{E-}8$$

$$Freq_{class3b10yr} = \frac{10}{3} * P_{class3b} * (CDF - LERF) = \frac{10}{3} * \frac{0.5}{218} * (2.74E\text{-}5 - 2.74E\text{-}6) = 1.89\text{E-}7$$

$$Freq_{class3b15yr} = \frac{15}{3} * P_{class3b} * (CDF - LERF) = 5 * \frac{0.5}{218} * (2.74E\text{-}5 - 2.74E\text{-}6) = 2.83\text{E-}7$$

The Seismic PRA results from the IPEEE Seismic Margins Analysis do not result in an estimate of CDF [Reference 32]. The 2014 Seismic Reevaluations for operating reactor sites [Reference 35] states the conclusions reached in 2010 by GI-199 [Reference 34] remain valid for estimating Seismic CDF at plants in the Central and Eastern United States, which includes GGNS. EPRI guidance [Reference 33] on recent seismic evaluations states, "EPRI does not recommend using any very conservative approaches to estimate the SCDF such as use of the maximum SCDFs calculated at any one frequency. This type of bounding approach is overly conservative and judged to not provide realistic risk estimates consistent with SCDFs calculated in actual SPRAs." Therefore, the average of the Seismic CDF values reported in Table D-1 of GI-199 [Reference 34] is calculated as follows:

$$\mathrm{CDF_{Seismic}} = (8.40\text{E-}6 + 1.10\text{E-}5 + 4.70\text{E-}6 + 9.40\text{E-}6)/4 = 8.38\text{E-}6$$

Similar to fire, the seismic LERF is estimated by applying a 10% LERF/CDF ratio, yielding an estimated seismic LERF of 8.38E-7. The following shows the calculation for Class 3b:

$$Freq_{class3b} = P_{class3b} * (CDF - LERF) = \frac{0.5}{218} * (8.38E\text{-}6 - 8.38E\text{-}7) = 1.73\text{E-}8$$

$$Freq_{class3b10yr} = \frac{10}{3} * P_{class3b} * (CDF - LERF) = \frac{10}{3} * \frac{0.5}{218} * (8.38E\text{-}6 - 8.38E\text{-}7) = 5.76\text{E-}8$$

$$Freq_{class3b15yr} = \frac{15}{3} * P_{class3b} * (CDF - LERF) = 5 * \frac{0.5}{218} * (8.38E\text{-}6 - 8.38E\text{-}7) = 8.64\text{E-}8$$

The fire and seismic contributions to Class 3b frequencies are then combined to obtain the total external event contribution to Class 3b frequencies. The change in LERF is calculated for the 1 in 10 year and 1 in 15 year cases and the change defined for the external events is shown in Table 5-17.

Table 5-17 – GGNS External Event Impact on ILRT LERF Calculation

Hazard	EPRI Accident Class 3b Frequency			LERF Increase (from 3 per 10 years to 1 per 15 years)
	3 per 10 year	1 per 10 year	1 per 15 years	
External Events	7.38E-08	2.46E-07	3.69E-07	2.95E-07
Internal Events	4.14E-09	1.38E-08	2.07E-08	1.66E-08
Combined	7.80E-08	2.60E-07	3.90E-07	3.12E-07

The internal event results are also provided to allow a composite value to be defined. When both the internal and external event contributions are combined, the total change in LERF of 3.12E-7 meets the guidance for small change in risk, as it exceeds 1.0E-7/yr and remains less than 1.0E-6 change in LERF. For this change in LERF to be acceptable, total LERF must be less than 1.0E-5. The total LERF value is calculated below:

$$\text{LERF} = \text{LERF}_{\text{internal}} + \text{LERF}_{\text{seismic}} + \text{LERF}_{\text{fire}} + \text{LERF}_{\text{class3Bincrease}}$$
$$= 7.74\text{E-}7/\text{yr} + 8.38\text{E-}7/\text{yr} + 2.74\text{E-}6/\text{yr} + 3.12\text{E-}7/\text{yr} = 4.66\text{E-}6/\text{yr}$$

As specified in Regulatory Guide 1.174 [Reference 4], since the total LERF is less than 1.0E-5, it is acceptable for the ΔLERF to be between 1.0E-7 and 1.0E-6.

5.2.7.1 Screened External Hazards

Several “other” external events were evaluated in the GGNS IPEEE. The IPEEE reported frequency of hazards from external floods, high winds, transportation accidents, and nearby facility accidents is “acceptably low” [Reference 32]. Since the time the IPEEE was performed, FLEX has been installed at GGNS to provide additional accident mitigation capabilities [Reference 48]. Additionally, some hazard reevaluations have been performed.

Additional analysis has been performed for external flooding since the IPEEE. On March 12, 2012, the Nuclear Regulatory Commission (NRC) issued a letter requesting information regarding Near-Term Task Force (NTTF) Recommendation 2.1 for flooding [Reference 43]. One of the required responses in the letter directed licensees to submit a Flood Hazard Reevaluation Report (FHRR). Entergy Operations, Inc. submitted the FHRR for Grand Gulf Nuclear Station (GGNS) on March 11, 2013 [Reference 44]. Entergy provided a response to the request for additional Information of the FHRR [Reference 45]. A second required response to Reference 43 directed licensees to submit an Integrated Assessment Report for any flood causing

mechanism that was not bounded by the current design basis. The FHRR showed three flooding mechanisms were not bounded by the current design basis (CDB) and were required to be evaluated in the Focused Evaluation (FE) [Reference 46]. The first mechanism, local intense precipitation (LIP), was calculated to generate a water level that exceeds the protected height of exterior doors, which lead to key SSCs. Therefore, GGNS committed to placing sandbags around the nine exterior probable maximum precipitation (PMP) doors (where the door seal is not credited) upon receipt of the precipitation forecast trigger. The second and third mechanisms not bounded by the CDB are the probable maximum flood (PMF) on Stream A and dam failure flooding with PMF of the Mississippi River. All buildings that have key SSCs have been shown to have adequate available physical margin since the flood water will not exceed the exterior door thresholds. Therefore, no water intrusion or accumulation is anticipated in rooms with key SSCs and the plant will be able to maintain all key safety functions (KSFs) throughout the event. There are no manual actions relied on, and no key SSCS are impacted from these events. Finally, for all three mechanisms, the Mitigating Strategies Assessment has demonstrated that mitigating strategies developed within FLEX will be available to maintain/restore KSFs as a defense-in-depth measure. Therefore, the evaluation of an acceptably low external flood risk remains valid.

The major concern in a high-wind or tornado scenario are the wind loads imposed on the buildings/major structures and the potential for wind-generated missiles to disable systems or components necessary to shut down the plant or maintain the plant in a safe shutdown condition. GGNS wind and tornado loadings are evaluated under Section 3.3 of UFSAR [Reference 47]. All Class I buildings and structures were designed to withstand 360 mph tornado winds, with is the vector sum of a maximum peripheral rotational velocity of 290 mph and a translational velocity of 70 mph, and a differential pressure drop of 3 psi with a maximum rate of change of 2 psi/sec with no loss of function. In addition, all Class I buildings and structures were also designed to withstand various postulated tornado generated missiles, including a 12-ft plank, 15-ft steel pipes, 3-ft steel rod, 35-ft utility pole, and 4000-lb automobile [Reference 47]. Since the GGNS IPEEE [Reference 32], RG 1.76 [Reference 45] was updated to lower the required design basis tornado wind speeds to 230 mph for the region in which GGNS is located. All GGNS FLEX equipment is stored in structures with designs that are robust such that no one external event can reasonably fail the FLEX capability [Reference 48]. There have been no major changes to the buildings/major structures or location of important safety equipment within them since the IPEEE submittals that negatively impact plant vulnerability to external events. Therefore, it is concluded that no new factors have been introduced at GGNS since the submittal of the IPEEE that would result in an increase in the risk associated with high winds, tornadoes, or tornado missiles.

No significant changes have been made that would affect the IPEEE evaluations of highway transportation, railroads, waterways, pipelines, military facilities, or industrial facilities. This evaluation is maintained in Section 2.2 of the UFSAR [Reference 47]. According to the Federal Aviation Administration’s Air Traffic Activity System, air traffic at the Jackson–Medgar Wiley Evers International Airport, the closest major airport serving commercial airlines, has significantly decreased since the time of the IPEEE. Based on the information summarized here from the IPEEE [Reference 32] and maintained in the UFSAR [Reference 47], these hazards are screened from this analysis.

5.2.8 Defense-In-Depth Impact

Regulatory Guide 1.174, Revision 3 [Reference 4] describes an approach that is acceptable for developing risk-informed applications for a licensing basis change that considers engineering

and applies risk insights. One of the considerations included in RG 1.174 is Defense in Depth. Defense in Depth is a safety philosophy that employs successive compensatory measures to provide accidents or mitigate damage if a malfunction, accident, or naturally caused event occurs at a nuclear facility. The following seven considerations will serve to evaluate the proposed licensing basis change for overall impact on Defense in Depth.

1. <u>Preserve a reasonable balance among the layers of defense.</u>

The usage of the risk metrics of LERF, population dose, and conditional containment failure probability collectively ensures the balance between prevention of core damage, prevention of containment failure, and consequence mitigation is preserved. The change in LERF is "small" per RG 1.174, and the change in population dose and CCFP are "small" as defined in this analysis and consistent with NEI 94-01 Revision 3-A.

2. <u>Preserve adequate capability of design features without an overreliance on programmatic activities as compensatory measures.</u>

The adequacy of the design feature (the containment boundary subject to Type A testing) is preserved as evidenced by the overall "small" change in risk associated with the Type A test frequency change.

3. <u>Preserve system redundancy, independence, and diversity commensurate with the expected frequency and consequences of challenges to the system, including consideration of uncertainty.</u>

The redundancy, independence, and diversity of the containment subject to the Type A test is preserved, commensurate with the expected frequency and consequences of challenges to the system, as evidenced by the overall "small" change in risk associated with the Type A test frequency change.

4. <u>Preserve adequate defense against potential CCFs.</u>

Adequate defense against CCFs is preserved. The Type A test detects problems in the containment which may or may not be the result of a CCF; such a CCF may affect failure of another portion of containment (i.e., local penetrations) due to the same phenomena. Adequate defense against CCFs is preserved via the continued performance of the Type B and C tests and the performance of inspections. The change to the Type A test, which bounds the risk associated with containment failure modes including those involving CCFs, does not degrade adequate defense as evidenced by the overall "small" change in risk associated with the Type A test frequency change.

5. <u>Maintain multiple fission product barriers.</u>

Multiple Fission Product barriers are maintained. The portion of the containment affected by the Type A test extension is still maintained as an independent fission product barrier, albeit with an overall "small" change in the reliability of the barrier.

6. <u>Preserve sufficient defense against human errors.</u>

Sufficient defense against human errors is preserved. The probability of a human error to operate the plant, or to respond to off-normal conditions and accidents is not significantly affected by the change to the Type A testing frequency. Errors committed during test and

maintenance may be reduced by the less frequent performance of the Type A test (less opportunity for errors to occur).

7. Continue to meet the intent of the plant's design criteria.

The intent of the plant's design criteria continues to be met. The extension of the Type A test does not change the configuration of the plant or the way the plant is operated.

5.3 Sensitivities

5.3.1 Potential Impact from Steel Liner Corrosion Likelihood

A quantitative assessment of the contribution of steel liner corrosion likelihood impact was performed for the risk impact assessment for extended ILRT intervals. As a sensitivity run, the internal event CDF was used to calculate the Class 3b frequency. The impact on the Class 3b frequency due to increases in the ILRT surveillance interval was calculated for steel liner corrosion likelihood using the relationships described in Section 5.2.6. The EPRI Category 3b frequencies for the 3 per 10-year, 10-year, and 15-year ILRT intervals were quantified using the internal events CDF. The change in the LERF, change in CCFP, and change in Annual Dose Rate due to extending the ILRT interval from 3 in 10 years to 1 in 10 years, or to 1 in 15 years are provided in Table 5-18 – Table 5-20. The steel liner corrosion likelihood was increased by a factor of 1000, 10000, and 100000. Except for extreme factors of 10000 and 100000, the corrosion likelihood is relatively insensitive to the results.

Table 5-18 – Steel Liner Corrosion Sensitivity Case: 3B Contribution

	3b Frequency (3-per-10 year ILRT)	3b Frequency (1-per-10 year ILRT)	3b Frequency (1-per-15 year ILRT)	LERF Increase (3-per-10 to 1-per-10)	LERF Increase (3-per-10 to 1-per-15)	LERF Increase (1-per-10 to 1-per-15)
Internal Event 3B Contribution	4.14E-09	1.38E-08	2.07E-08	9.67E-09	1.66E-08	6.91E-09
Corrosion Likelihood X 1000	4.19E-09	1.47E-08	2.37E-08	1.05E-08	1.95E-08	9.05E-09
Corrosion Likelihood X 10000	4.58E-09	2.24E-08	5.07E-08	1.78E-08	4.61E-08	2.83E-08
Corrosion Likelihood X 100000	8.56E-09	9.95E-08	3.21E-07	9.10E-08	3.12E-07	2.21E-07

Table 5-19 – Steel Liner Corrosion Sensitivity: CCFP

	CCFP (3-per-10 year ILRT)	CCFP (1-per-10 year ILRT)	CCFP (1-per-15 year ILRT)	CCFP Increase (3-per-10 to 1-per-10)	CCFP Increase (3-per-10 to 1-per-15)	CCFP Increase (1-per-10 to 1-per-15)
Baseline CCFP	5.76E-01	5.79E-01	5.82E-01	3.75E-03	6.42E-03	2.68E-03
Corrosion Likelihood X 1000	5.76E-01	5.80E-01	5.82E-01	3.79E-03	6.49E-03	2.71E-03
Corrosion Likelihood X 10000	5.76E-01	5.80E-01	5.83E-01	4.15E-03	7.11E-03	2.96E-03
Corrosion Likelihood X 100000	5.77E-01	5.85E-01	5.91E-01	7.74E-03	1.33E-02	5.53E-03

Table 5-20 – Steel Liner Corrosion Sensitivity: Dose Rate

	Dose Rate (3-per-10 year ILRT)	Dose Rate (1-per-10 year ILRT)	Dose Rate (1-per-15 year ILRT)	Dose Rate Increase (3-per-10 to 1-per-10)	Dose Rate Increase (3-per-10 to 1-per-15)	Dose Rate Increase (1-per-10 to 1-per-15)
Dose Rate	1.14E-03	3.81E-03	5.72E-03	2.67E-03	4.57E-03	1.91E-03
Corrosion Likelihood X 1000	1.16E-03	4.05E-03	6.55E-03	2.89E-03	5.39E-03	2.50E-03
Corrosion Likelihood X 10000	1.27E-03	6.18E-03	1.40E-02	4.91E-03	1.27E-02	7.82E-03
Corrosion Likelihood X 100000	2.36E-03	2.75E-02	8.85E-02	2.51E-02	8.62E-02	6.11E-02

5.3.2 Expert Elicitation Sensitivity

Another sensitivity case on the impacts of assumptions regarding pre-existing containment defect or flaw probabilities of occurrence and magnitude, or size of the flaw, is performed as

described in Reference 24. In this sensitivity case, an expert elicitation was conducted to develop probabilities for pre-existing containment defects that would be detected by the ILRT only based on the historical testing data.

Using the expert knowledge, this information was extrapolated into a probability-versus-magnitude relationship for pre-existing containment defects [Reference 24]. The failure mechanism analysis also used the historical ILRT data augmented with expert judgment to develop the results. Details of the expert elicitation process and results are contained in Reference 24. The expert elicitation process has the advantage of considering the available data for small leakage events, which have occurred in the data, and extrapolate those events and probabilities of occurrence to the potential for large magnitude leakage events.

The expert elicitation results are used to develop sensitivity cases for the risk impact assessment. Employing the results requires the application of the ILRT interval methodology using the expert elicitation to change the probability of pre-existing leakage in the containment.

The baseline assessment uses the Jeffreys non-informative prior and the expert elicitation sensitivity study uses the results of the expert elicitation. In addition, given the relationship between leakage magnitude and probability, larger leakage that is more representative of large early release frequency, can be reflected. For the purposes of this sensitivity, the same leakage magnitudes that are used in the basic methodology (i.e., 10 L_a for small and 100 L_a for large) are used here. Table 5-21 presents the magnitudes and probabilities associated with the Jeffreys non-informative prior and the expert elicitation used in the base methodology and this sensitivity case.

Table 5-21 – GGNS Summary of ILRT Extension Using Expert Elicitation Values (from Reference 24)

Leakage Size (L_a)	Expert Elicitation Mean Probability of Occurrence	Percent Reduction
10	3.88E-03	86%
100	2.47E-04	91%

Taking the baseline analysis and using the values provided in Table 5-8 – Table 5-10 for the expert elicitation sensitivity yields the results in Table 5-22.

Table 5-22 – GGNS Summary of ILRT Extension Using Expert Elicitation Values

Accident Class	ILRT Interval							
	3 per 10 Years				1 per 10 Years		1 per 15 Years	
	Base Frequency	Adjusted Base Frequency	Dose (person-rem)	Dose Rate (person-rem/yr)	Frequency	Dose Rate (person-rem/yr)	Frequency	Dose Rate (person-rem/yr)
1	1.10E-06	1.09E-06	2.76E+03	3.01E-03	1.07E-06	2.96E-03	1.06E-06	2.93E-03
2	1.49E-08	1.49E-08	4.73E+05	7.02E-03	1.49E-08	7.02E-03	1.49E-08	7.02E-03
3a	N/A	7.01E-09	2.76E+04	1.93E-04	2.34E-08	6.45E-04	3.50E-08	9.67E-04
3b	N/A	4.46E-10	2.76E+05	1.23E-04	1.49E-09	4.10E-04	2.23E-09	6.16E-04
7	1.46E-06	1.46E-06	4.12E+05	6.04E-01	1.46E-06	6.04E-01	1.46E-06	6.04E-01
8	1.78E-09	1.78E-09	3.10E+05	5.52E-04	1.78E-09	5.52E-04	1.78E-09	5.52E-04
Totals	2.58E-06	2.58E-06	1.50E+06	6.15E-01	2.58E-06	6.16E-01	2.58E-06	6.16E-01
ΔLERF (3 per 10 yrs base)	N/A				1.04E-09		1.78E-09	
ΔLERF (1 per 10 yrs base)	N/A				N/A		7.43E-10	
CCFP	57.43%				57.47%		57.50%	

The results illustrate how the expert elicitation reduces the overall change in LERF and the overall results are more favorable with regard to the change in risk.

6.0 RESULTS

The results from this ILRT extension risk assessment for GGNS are summarized in Table 6-1.

Table 6-1 – ILRT Extension Summary

Class	Dose (person-rem)	Base Case 3 in 10 Years		Extend to 1 in 10 Years		Extend to 1 in 15 Years	
		CDF/Year	Person-Rem/Year	CDF/Year	Person-Rem/Year	CDF/Year	Person-Rem/Year
1	2.76E+03	1.08E-06	2.98E-03	1.03E-06	2.84E-03	9.95E-07	2.75E-03
2	4.73E+05	1.49E-08	7.02E-03	1.49E-08	7.02E-03	1.49E-08	7.02E-03
3a	2.76E+04	1.66E-08	4.59E-04	5.55E-08	1.53E-03	8.32E-08	2.30E-03
3b	2.76E+05	4.14E-09	1.14E-03	1.38E-08	3.81E-03	2.07E-08	5.72E-03
7	4.12E+05	1.46E-06	6.04E-01	1.46E-06	6.04E-01	1.46E-06	6.04E-01
8	3.10E+05	1.78E-09	5.52E-04	1.78E-09	5.52E-04	1.78E-09	5.52E-04
Total		**2.58E-06**	**6.16E-01**	**2.58E-06**	**6.20E-01**	**2.58E-06**	**6.22E-01**
ILRT Dose Rate from 3a and 3b							
ΔTotal Dose Rate	From 3 Years	N/A		3.61E-03		6.18E-03	
	From 10 Years	N/A		N/A		2.58E-03	
%ΔDose Rate	From 3 Years	N/A		0.585%		1.003%	
	From 10 Years	N/A		N/A		0.642%	
3b Frequency (LERF)							
ΔLERF	From 3 Years	N/A		9.67E-09		1.66E-08	
	From 10 Years	N/A		N/A		6.90E-09	
CCFP %							
ΔCCFP%	From 3 Years	N/A		0.375%		0.642%	
	From 10 Years	N/A		N/A		0.268%	

7.0 CONCLUSIONS AND RECOMMENDATIONS

Based on the results from Section 5.2 and the sensitivity calculations presented in Section 5.3, the following conclusions regarding the assessment of the plant risk are associated with extending the Type A ILRT test frequency to 15 years:

- Regulatory Guide 1.174 [Reference 4] provides guidance for determining the risk impact of plant-specific changes to the licensing basis. Regulatory Guide 1.174 defines very small changes in risk as resulting in increases of CDF less than 1.0E-06/year and increases in LERF less than 1.0E-07/year. Since the ILRT does not impact CDF, the relevant criterion is LERF. The increase in internal events LERF resulting from a change in the Type A ILRT test interval from 3 in 10 years to 1 in 15 years is estimated as 1.66E-8/year using the EPRI guidance; this value increases negligibly if the risk impact of corrosion-induced leakage of the steel liners occurring and going undetected during the extended test interval is included. As such, the estimated change in LERF is determined to be "very small" using the acceptance guidelines of Regulatory Guide 1.174 [Reference 4].
- When external event risk is included, the increase in LERF resulting from a change in the Type A ILRT test interval from 3 in 10 years to 1 in 15 years is estimated as 3.12E-7/year using the EPRI guidance, and total LERF is 4.66E-6/year. As such, the estimated change in LERF is determined to be "small" using the acceptance guidelines of Regulatory Guide 1.174 [Reference 4]. The risk change resulting from a change in the Type A ILRT test interval from 3 in 10 years to 1 in 15 years bounds the 1 in 10 years to 1 in 15 years risk change. When external event risk is included, the increase in LERF resulting from a change in the Type A ILRT test interval from 1 in 10 years to 1 in 15 years is estimated as 1.30E-7 and the total LERF is 4.48E-6. Therefore, the risk increase is "small" using the acceptance guidelines of Regulatory Guide 1.174 [Reference 4].
- The effect resulting from changing the Type A test frequency to 1-per-15 years, measured as an increase to the total integrated plant risk for those accident sequences influenced by Type A testing, is 0.006 person-rem/year. NEI 94-01 [Reference 1] states that a "small" population dose is defined as an increase of ≤ 1.0 person-rem per year, or ≤ 1% of the total population dose, whichever is less restrictive for the risk impact assessment of the extended ILRT intervals. The results of this calculation meet these criteria. Moreover, the risk impact for the ILRT extension when compared to other severe accident risks is negligible.
- The increase in the conditional containment failure probability from the 3 in 10 year interval to 1 in 15 year interval is 0.642%. NEI 94-01 [Reference 1] states that increases in CCFP of ≤ 1.5% is "small." Therefore, this increase is judged to be small.

Therefore, increasing the ILRT interval to 15 years is considered to be insignificant since it represents a small change to the GGNS risk profile.

<u>Previous Assessments</u>

The NRC in NUREG-1493 [Reference 6] has previously concluded that:

- Reducing the frequency of Type A tests (ILRTs) from 3 per 10 years to 1 per 20 years was found to lead to an imperceptible increase in risk. The estimated increase in risk is very small because ILRTs identify only a few potential containment leakage paths that

cannot be identified by Type B or Type C testing, and the leaks that have been found by Type A tests have been only marginally above existing requirements.

- Given the insensitivity of risk to containment leakage rate and the small fraction of leakage paths detected solely by Type A testing, increasing the interval between integrated leakage-rate tests is possible with minimal impact on public risk. The impact of relaxing the ILRT frequency beyond 1 in 20 years has not been evaluated. Beyond testing the performance of containment penetrations, ILRTs also test integrity of the containment structure.

The findings for GGNS confirm these general findings on a plant-specific basis considering the severe accidents evaluated for GGNS, the GGNS containment failure modes, and the local population surrounding GGNS.

A. APPENDIX A: PRA TECHNICAL ADEQUACY

A.1. Internal Events PRA Quality Statement for Permanent 15-Year ILRT Extension

The current GGNS PRA model of record is model Revision 4b [Reference 17]. This model and its technical content was constructed and documented to meet the ASME/ANS PRA standard [Reference 49]. The PRA model quantification methodology used at Entergy Operations, Inc. (Entergy), nuclear sites is common and well-known to the industry.

Entergy's approach for maintaining, updating and documenting the PRA models at all Entergy nuclear sites is controlled in the fleet procedures. These procedures are consistent with the guidance of the ASME/ANS PRA standard [Reference 49]. The procedural process is comprehensive and detailed, which in turn provides the basis for establishing and maintaining the technical adequacy of the models, as well as ensuring the models reflect the as-built, as-operated plant configuration of the sites. Entergy procedures define the process to be followed to implement scheduled and interim PRA model updates and to control the PRA model files. Periodic PRA model updates are typically performed at least once every four years, with the option of extending the frequency for up to an additional two years, such that the total update period does not exceed six years. Extensions are justified by showing that the PRA model continues to adequately represent the as-built, as-operated plant and must be approved by management. Thus, using these models for this Type A test analysis meets technical adequacy requirements.

A.1.1 Peer Review Facts and Observations (F&Os)

The GGNS PRA model has undergone several peer reviews which document the model quality and identify any areas with potential for improvement. The following assessments have been performed and documented for the GGNS model.

- A peer review certification [Reference 50] of the GGNS PRA model Revision 1 was conducted by the Boiling Water Reactor Owners Group (BWROG) in October 1997 [Reference 51]. The peer review concluded that the GGNS PRA was sufficient to support meaningful rankings for the assessment of SSCs and judged capable of supporting absolute risk determination to support applications.
- A full-scope industry peer review of the GGNS PRA model Revision 4 [Reference 52] was conducted by the BWROG September 21-25, 2015 [Reference 53]. This peer review documented sixty-six (66) new F&Os including thirty-nine (39) Findings, twenty-six (26) Suggestions, and one (1) Best Practice. The peer review concluded that the GGNS PRA substantially (approximately 85% of the Supporting Requirements) met the ASME/ANS PRA standard at Capability Category II or better. This model revision was not issued for use because the PRA model was updated to Revision 4a to resolve the F&Os.

The GGNS PRA internal events model Revision 4a was approved in October 2017 [Reference 17] and incorporated changes, as applicable, to support the resolutions of the 2015 peer review findings. The 2015 peer review findings and the associated resolutions are documented in the model change request (MCR) database and a resolution summary report [Reference 54]. The full-scope peer review findings from 2015 were closed by an independent assessment conducted August 23-31, 2017. The closure assessment was conducted in accordance with Appendix X to NEI 05-04 [Reference 55] utilizing the conditions of acceptance stated in an NRC letter to the Nuclear Energy Institute dated May 3, 2017 [Reference 56]. The independent assessment is documented in the closure report [Reference 57] and concluded that none of the changes made to the GGNS PRA were considered a PRA upgrade or use of a new PRA method. All finding-level F&Os from the 2015 full-scope industry probabilistic risk assessment

peer review have been closed by an independent assessment conducted August 23-31, 2017 [Reference 54] and are listed in Table A-1. The table includes the resolutions and conclusions of the F&Os. In addition, the listing documents the basis for each F&O to validate whether the F&O constituted a PRA upgrade, maintenance update, or other; and documents the results from the independent assessment team review of the supporting requirements to ensure that Capability Category II of the ASME PRA standard was met for the F&Os.

Table A-1 List of Finding F&Os on the GGNS Internal Events PRA Model

F&O #	Applicable SR(s)	F&O Details	Resolution	Status	SR CC-II Met/Not Met	Maintenance Update or Upgrade	Importance to Application
1-3	QU-D4	This was not addressed as a comparison of results to similar plants was not conducted. Possible Resolution Provide a comparison similar to the comparison provided for some of the other technical elements.	A comparison to similar (all Mark III/BWR-6) plants was added to the Summary Report associated with the Rev 4 PRA model. Causes for significant differences in results between the plants were identified.	Resolved, Closed	QU-D4: Cat 2-3 MET per independent assessment of finding closure.	**Maintenance update.** Added documentation does not impact the methodologies used or change the PRA scope or capability. It is a comparison of results from the analysis.	This finding was closed and only pertains to documentation. Therefore, it has no impact on the ILRT analysis.
1-4	QU-F2 QU-F3	The documentation does not describe significant accident sequences in sufficient detail. Possible Resolution Describe the accident sequences in detail.	A detailed discussion of the significant accident sequences for both CDF and LERF was added to the Model Integration and Quantification Report for the internal events model Similarly, a detailed discussion of the significant accident sequences for both CDF and LERF was added to the Internal Flood Report for the flood scenarios.	Resolved, Closed	QU-F2: Cat 1-3 MET per BWROG peer review QU-F3: Cat 2-3 MET per independent assessment of finding closure.	**Maintenance update.** Added documentation does not impact the methodologies or change the PRA scope or capability. It is a discussion of results from the analysis.	This finding was closed and only pertains to documentation. Therefore, it has no impact on the ILRT analysis.
1-6	QU-F2	The documentation does not describe significant accident sequences in sufficient detail. A sensitivity study on LOOP recovery may be appropriate as the base case. The key sequences use a battery lifetime of 4 hours. Appears division II battery	A detailed discussion of the significant accident sequences for both CDF and LERF was added to the Model Integration and Quantification Report for the internal events model Similarly, a detailed discussion of the significant accident sequences for both CDF and LERF was added to	Resolved, Closed	QU-F2: Cat 1-3 MET per BWROG peer review	**Maintenance update.** Added documentation does not impact the methodologies used or change the PRA scope or capability. It is a discussion of results from the analysis. The sensitivity study	This finding was closed and only pertains to documentation. Therefore, it has no impact on the ILRT analysis.

Table A-1 List of Finding F&Os on the GGNS Internal Events PRA Model

F&O #	Applicable SR(s)	F&O Details	Resolution	Status	SR CC-II Met/Not Met	Maintenance Update or Upgrade	Importance to Application
		lifetime is 10 hours. Possible Resolution Refine analyses and upgrade documentation.	the Internal Flood Report. During the Peer Review, a sensitivity study on the loss of offsite power (LOOP) initiators was performed, and based on the sensitivity study, the Recovery Rule files were changed from using the normal weather recovery probabilities to using the average weather recovery probabilities. As documented in the LOOP timing analysis, RCIC operation is limited by suppression pool heat-up and/or Division I battery depletion while RCS depressurization is limited by Division II battery depletion. The time assumed for power recovery prior to RCIC loss is 4 hours (based on minimum design battery life), and the time assumed for power recovery prior to loss of RCS depressurization capability is 10 hours (based on calculated battery depletion time without load shed).			used the same underlying methodology. The battery lifetimes used in the analysis are division-specific.	
1-7	QU-F6	A quantitative definition of significant is not provided. Resolution Address	The quantitative definition of "significant" was added to the GGNS PRA Summary Report.	Resolved, Closed	QU-F6: Cat 1-3 MET per independent assessment	**Maintenance update.** Although the definition of significant was not included in the	This finding was closed and only pertains to documentation. Therefore, it has

Table A-1 List of Finding F&Os on the GGNS Internal Events PRA Model

F&O #	Applicable SR(s)	F&O Details	Resolution	Status	SR CC-II Met/Not Met	Maintenance Update or Upgrade	Importance to Application
					of finding closure	GGNS documentation, the evaluation of the results was based on the definition of significant provided in the Standard. Added documentation does not impact the methodologies used or change the PRA scope or capability.	no impact on the ILRT analysis.
1-8	QU-A2	RSC 14-15 (PRA Summary Report) provides results. Fault tree linking is used. Significant is not defined but sequences are rank ordered and provide a high percentage of the CDF results. [There are errors in the initiating event frequencies, wrong version of database was used, such that a new quantification is needed. In addition, there are conservatisms in significant accident sequences which should be addressed. Primarily in the DC lifetime for division II which could impact the	The quantitative definition of "significant" was added to the GGNS PRA Summary Report, and the GGNS PRA Uncertainty and Sensitivity Report. These reports also identify the risk significant accident sequences based on this definition. The Initiating Events Report was updated to ensure that it specified which column of values should be used in the CAFTA .RR file, and the .RR file used for quantification was updated to ensure it contains the values from the correct column. As documented in the LOOP timing analysis, RCIC operation is limited by suppression pool heat-up	Resolved, Closed	QU-A2: Cat 1-3 MET per independent assessment of finding closure	**Maintenance update.** Although the definition of significant was not included in the GGNS documentation, the evaluation of the results was based on the definition of significant provided in the Standard. Added documentation does not impact the methodologies or change the PRA scope or capability. The initiating event issue was a translation error when the values	This finding was closed and only pertains to documentation. Therefore, it has no impact on the ILRT analysis.

Table A-1 List of Finding F&Os on the GGNS Internal Events PRA Model

F&O #	Applicable SR(s)	F&O Details	Resolution	Status	SR CC-II Met/Not Met	Maintenance Update or Upgrade	Importance to Application
		top two sequences and several others.] Possible Resolution Correct the model input and re-quantify.	and/or Division I battery depletion while RCS depressurization is limited by Division II battery depletion. The time assumed for power recovery prior to RCIC loss is 4 hours (based on minimum design battery life), and the time assumed for power recovery prior to loss of RCS depressurization capability is 10 hours (based on calculated battery depletion time without load shed).			were transferred from the IE notebook to the RR file. The underlying methodology to calculate the initiating event values and for quantification were not affected by correcting the values. The battery lifetimes used in the analysis are division-specific.	
1-12	LE-E4	The LERF is quantified using the same general process as the CDF and is documented in the QU notebook. The review of the LE quantification against the requirements of Tables 2-2.7-2(a), (b) and (c) is essentially identical to the CDF reviews documented under the QU High Level Requirement. Direct linking of the Level 1 sequences with the CET provides assurance that all system dependencies are captured, etc. A LERF truncation sensitivity was performed, but does not meet the	The updated quantification of the Internal Events PRA and the Internal Flood PRA both now show convergence for both the pre-recovery and the post-recovery cases. The revised quantitative uncertainty analysis yields a mean value of CDF that is greater than the mean value of LERF.	Resolved, Closed	LE-E4: Cat 1-3 MET per BWROG peer review	**Maintenance update.** A review of the LERF model identified an error in the LERF model where a gate that was supposed to be an AND gate was inadvertently modeled as an OR gate. With this error corrected, convergence was obtained, and the LERF was calculated to be a decade lower than CDF, as expected. Correction of the modeling error to achieve convergence	This finding was closed and the ILRT analysis used the model with the LERF model error corrected. Therefore, it has no impact on the ILRT analysis.

Table A-1 List of Finding F&Os on the GGNS Internal Events PRA Model

F&O #	Applicable SR(s)	F&O Details	Resolution	Status	SR CC-II Met/Not Met	Maintenance Update or Upgrade	Importance to Application
		criterion identified in the QU notebook. However, the truncation was as low as could be achieved, and the lack of convergence does not significantly affect the results. Also when uncertainty is considered LERF mean value is calculated to exceed mean CDF value. This is not possible. Possible Resolution Consider the reasons and address.				did not impact the methodologies used or change the PRA scope or capability.	
1-13	IFPP-A5	Walkdowns are documented in RSC 13-20 Internal Flooding Walkdown Documentation. In general, this information was found to substantiate the flood zone definition discussions in Section 4.0 of RSC 13-37, Revision 0 (Internal Flooding Analysis). Flooding scenarios associated with Control Building area 0C125, which contribute to approximately 5% CDF may be overly conservative. Based on discussions with GG PRA	Correction made to the equipment location mapping (OC215 replaced 0C125) in the flooding analysis software (TIFA) and FRANX database. Room OC215 has no flood sources, so no new scenarios were introduced by the correction of this mapping.	Resolved, Closed	IFPP-AS: Cat 1-3 MET per BWROG Peer Review	**Maintenance update.** The DC equipment was incorrectly mapped to room 0C125 rather than OC215. Correction of the mapping error did not result in new scenarios and did not impact the methodology used or change the PRA scope or capability.	This finding was closed, did not result in new scenarios, and the ILRT analysis used the model with the error corrected. Therefore, it has no impact on the ILRT analysis.

Table A-1 List of Finding F&Os on the GGNS Internal Events PRA Model

F&O #	Applicable SR(s)	F&O Details	Resolution	Status	SR CC-II Met/Not Met	Maintenance Update or Upgrade	Importance to Application
		consultants, these scenarios were dominant due to the presence of DC equipment in this room, as documented in the GG equipment database. However, this critical equipment is not located in this area. Possible Resolution Reevaluate the subject scenarios and equipment locations.					
2-1	IE-C15	The mean values provided in the IE Notebook were not used in the quantification of the PRA results. The values from Table 9 in the IE Notebook were not correctly used in the CAFTA model. Possible Resolution Update the CAFTA database to reflect the updated initiating event analysis mean value frequencies.	The Initiating Events Report was updated to ensure that it specified which column of values should be used in the CAFTA .RR file, and the .RR file used for quantification was updated to ensure it contains the values from the correct column.	Resolved, Closed	IE-C15: Cat 1-3 MET per independent assessment of finding closure	**Maintenance update.** This was a translation error when the values were transferred from the IE notebook to the RR file. The underlying methodology to calculate the initiating event values and for quantification were not affected by correcting the values, nor was there a change to the PRA scope or capability.	This finding was closed and the ILRT analysis used the model with the database error corrected. Therefore, it has no impact on the ILRT analysis.
3-1	IE-C12 IE-C4	Table 6 of the initiating events report shows data used for Bayesian updating of plant specific initiating events. In some	Based on a review of the Plant-specific Data Analysis and Initiating Events Reports, there was a typo in the Prior Frequency Mean value for	Resolved, Closed	IE-C4: Cat 1-3 MET per BWROG Peer Review IE-C12: Cat	**Maintenance update.** The issue associated with %T2 was a typo, for which the resolution did not	This finding was closed and the ILRT analysis used the model with the

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		cases it appears that the plant experience would imply a substantially higher frequency than the prior data. For example for %T2 the prior is 1.12E-2 /yr whereas the plant specific experience is ~0.3/yr. Also for %TSTT1 the prior is 8.80E-3 /yr whereas the plant experience is ~0.13/yr. These differences are large enough that the prior may not be appropriate for Bayesian updating. Some explanation of this difference is warranted especially with regard to the Bayesian process. Also since the experience timeframe covers a period of much earlier GGNS operation, it is possible that more recent data is better because of plant fixes. Possible Resolution Provide justification for this deviance or consider alternate methods for calculating the IE frequencies.	%T2 (LOCHS) and corresponding spreadsheet. The value should be 1.12E-1 instead of 1.12E-2. The values were updated in the Initiating Events Report, the associated spreadsheet, and the CAFTA .RR file. The analysis for %TSTT1 incorrectly included the Loss of Switchyard Power Lines in both the LOOP and the %TSTT1 IE frequencies, rather than the LOOP frequency only. Correction of the analysis reduced the frequency for %TSTT1 to be comparable to the generic estimate. The current value is 9.19E-3/yr.		1-3 MET per BWROG Peer Review	impact the methodology or change the PRA scope or capability. The issue associated with %TSTT1 was inclusion of non-applicable data when evaluating the IE frequency for transformer ST11. The underlying methodology or the PRA scope or capability were not changed, but the classification of the events was corrected to apply only to the LOOP frequency.	database error corrected. Therefore, it has no impact on the ILRT analysis.
3-2	IE-C15 IE-C2	Table 9 of the Initiating Events Notebook includes	The Initiating Events Report was updated to ensure that it	Resolved, Closed	IE-C2: Cat 1-3 MET per	**Maintenance update.** This was a	This finding was closed and the

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		a summary of the Initiating Events Frequencies derived from the updated IE analysis. The Frequency per reactor year (the fourth column from the left) shows the final updated number that should be used for quantification. However, the IE frequencies used for quantification have come from other columns that do not represent the most recent data. Possible Resolution Correct this transposition error.	specified which column of values should be used in the CAFTA .RR file, and the .RR file used for quantification was updated to ensure it contains the values from the correct column.		BWROG Peer Review IE-C15: Cat 1-3 MET per independent assessment of finding closure	translation error when the values were transferred from the notebook to the RR file. The underlying methodology to calculate the initiating event values or for quantification were not affected by correcting the values, nor was there a change to the PRA scope or capability.	ILRT analysis used the model with the database error corrected. Therefore, it has no impact on the ILRT analysis.
4-4	HR-F1	There are multiple human failure events (HFEs) for performing the same action, only on a different piece of equipment. For example, there are three different HFEs for failing to start standby air compressors. If an operator fails to start a compressor, they likely fail to start any compressor, not just one in particular. There should be only one failure for the operator to start a compressor that fails the	A review of the HFEs in the GGNS model of record (MOR) was performed to identify those for performing the same action on different pieces of equipment within the same system. A total of 16 individual HFEs were replaced with 6 common HFEs for the actions. The common HFEs have the same value of the individual HFEs they replaced, which is effectively a dependency of 1.0, instead of assigning a dependency of 1.0 during the dependency analysis. These changes were made in	Resolved, Closed	HR-F1: Cat 1-2 MET per BWROG Peer Review	**Maintenance update.** The methodology used for the calculation of the HEP values, and the PRA scope or capability, are not impacted by this change.	This finding was closed and the ILRT analysis used the model with the database error corrected. Therefore, it has no impact on the ILRT analysis. The pending documentation update to the System Analysis Report to reflect the

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		action for all air compressors. Otherwise there are failed and unfailed actions in the model to start the compressor. Possible Resolution Group similar operator actions into one action.	the Rev 4a MOR, HRA Report, Quantification Report, and Summary Report. The affected System Analysis Report Appendices will be updated per a Model Change Request (MCR).				new HFE names also has no impact on ILRT analysis.
4-5	HR-F2 HR-H2	The timing of cues is not explicitly documented in the HRA calculator. The time delay to the cue is set to zero in every instance. The time delay is an important step because it can limit the amount of time in the scenario to recover from the action. The only timing listed in the time window is the median response and execution time. Operator recovery is based on the remaining time available, but without the time delay to the cue included, more time is allowed to recover than is actually available. Possible Resolution Use the identified delay times in the HRA calculator to accurately reflect the timing of the	Time delays were added into the HRA Calculator, and the dependency analysis was updated using the new information.	Resolved, Closed	HR-F2: Cat 2 MET per independent assessment of finding closure HR-H2: Cat 1-3 MET per BWROG Peer Review	**Maintenance update.** The HRA Calculator is used for the calculation of the human error probabilities (HEPs). Inclusion of the timing of cues does not impact the calculated HEP but could impact the "order" of the HFEs in the dependency analysis. The methodology used for the dependency analysis, and the scope and capability of the PRA are not changed by including the timing of cues. The inclusion of the cues helps to ensure correct ordering of the HFEs in a combination during	This finding was closed and the ILRT analysis used the model with the time delays added to the HRA Calculator. Therefore, it has no impact on the ILRT analysis.

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F&O #	Applicable SR(s)	F&O Details	Resolution	Status	SR CC-II Met/Not Met	Maintenance Update or Upgrade	Importance to Application
		actions in the scenario and recovery actions.				the dependency analysis.	
4-6	HR-F2 HR-G4	Scenario timeframes are included in the evaluation of the HFE. However, there are no references to where the scenario timeframes are calculated. There was some indication that MAAP had been used in the past to develop the scenarios, but nothing could be found to support the times used. Following plant uprate a scaling evaluation of the increased power was performed to revise the scenario times. Additional MAAP cases were performed following the uprate, but these have not been incorporated into the HFE analysis. Possible Resolution Determine the reference for each scenario timeframe and document the link between the HFE and the reference.	As documented in the Success Criteria Report, new MAAP thermal/hydraulic analyses were done after the extended power uprate to support the Rev. 4 PRA update. Scenario time frames were reviewed and addressed by adding the delay times for the HEP cues. The bases for the HFE timing were updated based on the new MAAP analyses and documented in the timing notes in the HRA Calculator database and in a detailed table on HFE timing in the HRA Report.	Resolved, Closed	HR-F2: Cat 2 MET per independent assessment of finding closure HR-G4: Cat 2 MET per BWROG Peer Review	**Maintenance update.** The methodology used by the HRA Calculator to calculate HEPs, and the PRA scope and capability were not impacted by documenting the updated bases for the HFE time frames.	This finding was closed and only pertains to documentation. Therefore, it has no impact on the ILRT analysis.
4-7	HR-G2	All operator actions include an estimation of the failure in cognition. However, a number of operator actions had the	The updated HRA evaluation no longer sets the execution probability to zero and instead is based on the maximum	Resolved, Closed	HR-G2: Cat 1-3 MET per BWROG Peer Review	**Maintenance update.** For HFEs where no execution contribution was included, the	This finding was closed and the ILRT analysis used the model with the

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		execution failure probability set to zero stating that the action is memorized and practiced routinely. These actions are in the first few minutes following an initiating event and based on the time available may have high HEPs. Possible Resolution Include execution failure probabilities for all operator actions.	combined value for the CBDTH/NCR approach.			execution actions were added using the same methods as for all other HFEs. The underlying HRA methodology, and the PRA scope and capability were not impacted by adding additional detail for some of the HFEs.	execution probability no longer set to zero in the HRA Calculator. Therefore, it has no impact on the ILRT analysis.
4-10	HR-H3 HR-G7	The independent evaluation of HFEs did not include any delay time to the cue. This carried forward into the dependency analysis where all HFEs were evaluated to have the same delay time of zero. This paired events that should be separated in the accident sequence by hours together resulting in dependent combinations that should not exist or have a lower dependency. With all of the actions having the same delay time, complete dependence was calculated resulting in	Time delays were added into the HRA Calculator, and the dependency analysis was updated using the new information. In addition, the most significant HFE combinations were reviewed as part of the dependency analysis for separation of events and intervening successes. When identified, the default dependency was adjusted in the HRA Calculator software.	Resolved, Closed	HR-H3: Cat 1-3 MET per BWROG Peer Review HR-G7: Cat 1-3 MET per independent assessment of finding closure	**Maintenance update.** The HRA Calculator is used for the calculation of the HEPs. Inclusion of the timing of cues and consideration of intervening successes does not impact the calculated HEP but could impact the “order" of the HFEs in the dependency analysis. The methodology used for the dependency analysis, and the scope and capability of the PRA are not changed by including	This finding was closed and the ILRT analysis used the model with the time delays added to the HRA Calculator. Therefore, it has no impact on the ILRT analysis.

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		much higher dependent failure probabilities than actually exist. The HRA calculator software has overrides available to offset delay times or reduce dependence, but these were not used. There also does not appear to be any evaluation of intervening successes which would remove the dependence between actions. Possible Resolution Perform the dependency analysis using accurate delay times. Include review for intervening successes.				the timing of cues and consideration of intervening successes.	
4-13	DA-C3	A number of component types were excluded from the evaluation including motor operated valves, air operated valves, and temperature switches in PSA-GGNS- 01-DA-01. These component types were not reviewed for plant specific failures to determine if Bayesian updating of the generic failure data should be performed. Possible Resolution	Additional plant-specific data was obtained for various valves and air compressors which were previously not included in the PRA. The new data includes number and type of failures, demand data, and exposure data per component and type code, and this data was analyzed consistent with the established data analysis Bayesian update methodology. The new data was compiled into the	Resolved, Closed	DA-C3: Cat 1-3 MET per independent assessment of finding closure	**Maintenance update.** Using Bayesian updating to evaluate reliability data for additional component types did not result in a change in methodology or in the scope or capability of the PRA.	This finding was closed, the change did not significantly affect the failure probabilities in the model, and the ILRT analysis used the model with updated failure probabilities. Therefore, it has no impact on

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		Include evaluation of these component types and subtypes so that plant specific data can be evaluated for inclusion to the generic failure rates.	spreadsheets used for the data analysis, and all changes and additions were documented in the Plant-Specific Data and CCF Report.				the ILRT analysis.
4-14	DA-C3	The failures removed from consideration do not have adequate justification for disregarding previous plant failures. Many failures were removed in previous model revisions, but there is no documentation as to why the failures were no longer applicable. Possible Resolution Develop bases for failure inclusion and exclusion and document the failures using the bases.	The bases for failure inclusion and exclusion are established in the Plant-Specific Data and CCF Report, where it is now documented that all failures included in the PRA must have occurred during the time frame for the PRA update (September 1, 2006 through August 31, 2012) and must meet the definition of a PRA functional failure.	Resolved, Closed	DA-C3: Cat 1-3 MET per independent assessment of finding closure	**Maintenance update.** Enhancement of the documentation to describe the bases for excluding some equipment failure data does not impact the methodology used or change the PRA scope or capability.	This finding was closed and only pertains to documentation. Therefore, it has no impact on the ILRT analysis.
4-15	DA-C13	One discrepancy was identified for battery charger unavailability. In the notebook unavailability was calculated for the L51 battery chargers based on past history. However, the reliability database had zero unavailability for each of the battery chargers. Possible Resolution	The unavailability data for the 125V DC battery chargers was updated as documented in the Plant-Specific Data and CCF Report. All unavailability data was reviewed for similar concerns, and data for the following were also updated: radial well pumps, air compressors, AC circuit breakers, and switchyards.	Resolved, Closed	DA-C13: Cat 2-3 MET per BWROG Peer Review	**Maintenance update.** Update of unavailability data for several components to be consistent with plant operating history does not involve a change in methodology or change the PRA scope or capability.	This finding was closed and the ILRT analysis used the model with updated unavailability data. Therefore, it has no impact on the ILRT analysis.

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F&O #	Applicable SR(s)	F&O Details	Resolution	Status	SR CC-II Met/Not Met	Maintenance Update or Upgrade	Importance to Application
		Update the model unavailabilities for 125V DC battery chargers.					
4-17	DA-C14	Coincident unavailability was identified to occur in the data analysis timeframe (PSA-GGNS-01-DA-01). This unavailability is not included in the model so is therefore not included in the final results. Possible Resolution Include coincident maintenance in the model where analysis has determined it exists.	A thorough review of previous analyses and the current system notebooks determined that the previously modeled coincident unavailabilities did not meet the criteria for inclusion. It was confirmed that no more than one safety-related system is scheduled to be in maintenance at any given time. The Plant-Specific Data and CCF Report was updated to document this review and information.	Resolved, Closed	DA-C14: Cat 1-3 MET per independent assessment of finding closure	**Maintenance update.** Enhancement of the documentation to describe the plant practices and criteria for modeling coincident unavailability did not change the methodology for modeling maintenance unavailability, or the PRA scope or capability.	This finding was closed and only pertains to documentation. Therefore, it has no impact on the ILRT analysis.
4-19	DA-E1	There are numerous conflicts between the two data analysis notebooks and the two common cause notebooks. This is likely due to a two-year gap between publishing of the notebooks. Information is not consistent between notebooks and even within the same notebook. The final data rollup notebook appears to be accurate, but its information is based off the plant specific	All data documentation was aggregated into a single Plant-Specific Data and CCF Report, which directly incorporates the supporting calculation spreadsheets, and describes the formulas used in the spreadsheets.	Resolved, Closed	DA-E1: Cat 1-3 MET per independent assessment of finding closure	**Maintenance update.** Consolidation, consistency update, and enhancement of documentation did not change the underlying data analysis methodologies or change the scope or capability of the PRA.	This finding was closed and only pertains to documentation. Therefore, it has no impact on the ILRT analysis.

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		notebook which has information that is out of date, not used, and results in contradictory information to the data development notebook. The same is true of the common cause notebooks. Much of the plant specific data (run and demand estimates, maintenance unavailability data) was not found in the notebooks, but in spreadsheets provided separately. This information should be included in the notebook for ease in identification. Possible Resolution Resolve conflicts between notebooks and include supplementary data into the notebooks.					
5-4	SC-A5 AS-B7	DC battery life is presented as 4 hours in the SC notebook, but the Div II battery was credited to 10 hours per the LOSP notebook. The documentation is not consistent, and it is not clear if an operator action for load shedding is	As documented in the LOOP timing analysis, RCIC operation is limited by suppression pool heat-up (MAAP runs that credit RCIC under SBO conditions) and/or Division I battery depletion while RCS depressurization is limited by Division II battery depletion. The time assumed	Resolved, Closed	SC-A5: Cat 2-3 MET per BWROG peer review As-B7: Cat 1-3 MET per BWROG Peer Review	Maintenance **update.** Enhancement of the documentation to clarify the division-specific battery depletion times used in the analysis does not change the analysis methodologies are	This finding was closed and only pertains to documentation. Therefore, it has no impact on the ILRT analysis.

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		required. Possible Resolution Determine realistic battery life times with and without load shedding, and model with any necessary HEPs in the PRA.	for power recovery prior to RCIC loss is 4 hours (based on Div. I minimum design battery life), and the time assumed for power recovery prior to loss of RCS depressurization capability is 10 hours (based on Div. II calculated battery depletion time without load shed). The DC Power system analysis documentation was updated to reference the division-specific battery lifetime from the LOSP analysis and revise the battery depletion assumption. The Success Criteria Report was also updated to document the division-specific battery depletion times.			used or change the PRA scope or capability.	
5-6	AS-B7	AC power recoveries are developed on a cutset level to account for timing in the LOSP notebook (report PSA- GGNS-01-IE-01). Spot checks of the Qrecover file compared to the notebook identified the following errors/ inconsistencies: ZHE-OSP-DSG0-NW - used the "average" recovery of 6.56E-1 ZHE-OSP-DLG0-NW -	The recovery factor typos documented in the F&O were corrected. A detailed review of the remaining AC power recovery rules found no additional issues. During the Peer Review, a sensitivity study on the loss of offsite power (LOOP) initiators was performed, and based on the sensitivity study, the Recovery Rule files were changed from using the normal weather recovery	Resolved, Closed	AS-B7: Cat 1-3 MET per BWROG Peer Review	**Maintenance update.** Correction of typographical errors in recovery factors and update to include more appropriate offsite power recovery factors for average weather and long-term scenarios does not change the underlying methodology used to calculate the	This finding was closed and the ILRT analysis used the model with updated recovery factors. Therefore, it has no impact on the ILRT analysis.

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		was entered into the Qrecover file with a probability of 1.22E-2 instead of 1.22E-1. Approximately 10 other events were spot checked and found to be entered properly. Additionally, the normal weather offsite power recovery data were applied to all the LOSP initiating events. The weighted average of the offsite power recovery probabilities did not include the severe weather portion in the weighting. This makes the application of the non-recovery probabilities non-conservative Finally, the GG PRA team self-identified that offsite power recoveries for failure of DHR sequences was overly conservative, more aligned with loss of makeup timing than loss of DHR timing. The GG team performed a sensitivity that significantly reduced CDF and LERF. Possible Resolution Review the entire list of offsite power recovery	probabilities to using the average weather recovery probabilities. The timing for long term scenarios was addressed by a sensitivity study documented in the peer reviewed Quantification Report which has now been included in the base model.			recovery probabilities or change the PRA scope or capability.	

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		events to confirm they are entered into the Qrecovery file properly. Apply normalized offsite power non-recovery probabilities that include the severe weather component. Re-evaluate the offsite power non-recovery probabilities for loss of DHR sequences to consider realistic probabilities.					
5-7	AS-A7	The very small LOCA (%S3) was identified as an initiating event in the IE analysis. In Table 1 of the AS notebook, it was listed as being treated as a transient. However, no basis is given, and the %S3 initiating event is not included in the CAFTA model. Possible Resolution Either provide a defendable basis for excluding the very small LOCA, or develop it for analysis.	The %S3 initiating event was added to the list of transient events in the Accident Sequence Analysis Report because it can be mitigated by the same equipment as a transient initiating event. This is consistent with inclusion as a transient event in the PRA model logic.	Resolved, Closed	AS-A7: Cat 1-2 MET per BWROG Peer Review	**Maintenance update.** Clarification of the documentation on the treatment of very small LOCA does not change the methodology for identification and grouping of initiating events or change the PRA scope or capability.	This finding was closed and only pertains to documentation. Therefore, it has no impact on the ILRT analysis.
5-8	AS-B1 SC-B3	The small and medium LOCA ATWS scenarios do not appear to have considered the LOCA	The Success Criteria Report was updated to document that any medium LOCA or large LOCA with failure of rod	Resolved, Closed	AS-B1: Cat 1-3 MET per BWROG Peer Review	**Maintenance update.** Enhancement of the documentation on the	This finding was closed and only pertains to documentation.

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		effects on system success criteria, such as SLC. Large LOCA ATWSs have not been addressed with either a valid qualitative argument or a quantitative evaluation. A success criteria basis could not be found for using RCIC to depressurize to allow SDC in transients or ATWS. In transient sequences with success of depressurization, SDC is credited to prevent core damage, which disagrees with the MAAP calculation RSC-CALMAP-2014-1202, which shows this sequence as core damage. Possible Resolution Document the success criteria for LOCA ATWS events. Document bases for use of RCIC and SDC to make a sequence a safe, stable end state. If this cannot be justified, should be considered core damage. Remove credit for depressurization/SDC to prevent core damage in transients.	insertion is assumed to lead to core damage. A small LOCA would not impact the mechanical or electrical reactor protection system (RPS), or the ability to manually scram, perform alternate rod insertion, or trip the recirculation pumps. Therefore, the only system in question for a small LOCA ATWS is standby liquid control (SLC). Based on the system design criteria for SLC, and in accordance with GDC 4, SLC is designed to operate following a LOCA. Therefore, the leakage during a small LOCA is not large enough to render SLC ineffective regardless of the location of the leak. The Success Criteria Report also documents that RCIC is not credited as a method of depressurization in the transient or ATWS accident sequences. Decay heat removal options with successful RCIC injection are limited to RHR in Suppression Pool Cooling (SPC) Mode and RHR in Containment Spray (CS) Mode. Decay heat removal via RHR in Shutdown Cooling (SDC) Mode is not		SC-B3: Cat 1-3 MET per BWROG Peer Review	success criteria for LOCA ATWS does not change the methodology to define accident sequence progression. There is also no change to the PRA scope or capability.	Therefore, it has no impact on the ILRT analysis.

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			credited as a viable option when RCIC is injecting for inventory control. A new MAAP calculation was performed for a transient with depressurization in which LPCI and SPC alternate based on RPV level. The plant reaches a safe stable state after 24 hours. Based on the similarity of flow between the LPCI/SPC alignment and SDC, this case also provides a basis to credit SDC.				
5-9	SC-B1 SC-B2	GGNS assumes that suppression pool makeup (SPMU) is required in combination with containment venting in order to avoid cavitation of ECCS pump suction in containment heat-up sequences. The assumption that venting fails the ECCS pumps is conservative, which is noted in Topic 7 of Table 11 of the QU notebook. Regarding SPMU successfully facilitating pump operation, there is no analytical basis for this success criteria, but instead is based upon the	SPMU is only required for large and medium LOCAs that experience failure of decay heat removal. For large LOCA, the ECCS pumps are assumed to fail due to loss of NPSH if containment venting or containment failure occurs. The above assumptions are based on MAAP analysis showing SP level drops to the SPMU limit shortly after the sequence mission time. The ECCS pumps can pump saturated water if SP level remains above SPMU limit, unless there is flashing of the SP water, steam entrapment, cavitation, or a pump trip when containment fails.	Resolved, Closed	SC-B1: Cat 2 MET per BWROG Peer Review SC-B2: Cat 2-3 MET per BWROG Peer Review	**Maintenance update.** Enhancements to documentation to clarify and provide the analytical basis for analysis assumptions does not impact the methodology used to determine accident sequence progression or success criteria. There is also no change to the PRA scope or capability.	This finding was closed and only pertains to documentation. Therefore, it has no impact on the ILRT analysis.

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		expert judgment of the modeler. While this may be a reasonable assumption, it would be better to have an analytical basis or at least carry this item as an additional source of modeling uncertainty. Since these assumptions are a significant driver to the CDF and LERF, consideration should be given to attempt to refine the assumption. At a minimum, sensitivity analyses should be performed to ensure the impact of these SC assumptions are fully understood for risk characterization. Possible Resolution Since these assumptions are a significant driver to the CDF and LERF, consideration should be given to attempt to refine the assumptions. At a minimum, sensitivity analyses should be performed to ensure the impact of this SC assumption are fully understood for risk characterization.	However, injection of CST volume will increase level in the SP and the potential for trip was eliminated in most of cases. The use of HPCS after containment failure is now addressed in the Accident Sequence and Success Criteria Reports.				

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5-10	LE-A2	The characteristics identified as important in LE-A1 are documented in Section 1 of the LE notebook (PSA-GGNS-01-LE). However, the LE notebook does not provide any bases for the binning of sequences (e.g., determination of which sequences are high pressure and which are low). Per the Grand Gulf PRA team, selection was based on information from MAAP gathered from both success criteria and LERF-specific assessments and the engineer's experience working on other BWR 6 designs. This SR is considered met because the binning appears reasonable in most cases, but documentation of more definitive bases is needed. Some examples of sequences for which the high/low pressure binning are not obvious are: P-009 (SORV, RCIC initially successful, but LPI fails and RX depressurization not questioned) is "Low"	The LERF Report was updated to clearly define the high to low pressure transition at 200 psig, based on MAAP analysis. The updated report also clarifies that only the pressure at the time of RPV failure is relevant for this binning criterion. This resulted in a change to the binning of small LOCA sequences with successful depressurization prior to RPV failure to low pressure scenarios.	Resolved, Closed	LE-A2: Cat 1-3 MET per BWROG peer review	**Maintenance update.** Enhancement of the documentation, assumptions and bases for sequence binning did not change the methodology used for binning or result in a change to PRA scope or capability.	This finding was closed and the ILRT analysis used the updated model. Therefore, it has no impact on the ILRT analysis.

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F&O #	Applicable SR(s)	F&O Details	Resolution	Status	SR CC-II Met/Not Met	Maintenance Update or Upgrade	Importance to Application
		pressure, and all Small LOCAs (even with depressurization successful) are binned as high pressure. Possible Resolution Document the bases for the binning of the characteristics. Qualitative evaluation of many of the sequences is intuitive (e.g., large LOCAs are low pressure), but some detail should be provided for the binning of less obvious sequence characteristics. Clearly identify the criterion for high vs. low pressure binning (200 psi).					
5-12	LE-C10 LE-C12 LE-F2 LE-C3 LE-G3 LE-G6	There is no quantitative definition of significant accident progression sequences. There are SRs that require documenting the quantitative definition, as well as review of the significant severe accident progression sequences for possible credit for repairs and engineering analyses to provide a more realistic analysis. An example of the lack of reviews for	The quantitative definition of "significant accident progression" was added to the Model Integration and Quantification Report. Analysis Report documents the basis of the accident sequence progression. The Quantification Report was updated to discuss the review and relative contributions of the LERF sequences, and the Summary Report was updated to provide a comparison of initiating event and other	Resolved, Closed	LE-C3, LE-C10, LE-C12: Cat 2 MET per independent of finding closure LE-F2: Cat 1-3 MET per independent assessment of finding closure LE-G3: Cat 2 MET per	**Maintenance update.** Update of the LERF model and results with the updated igniter HEP did not require a change in methodology or PRA scope or capability, but updated insights were obtained. Additional review and enhanced documentation of the LERF results	This finding was closed and the ILRT analysis used the model with the update HEP. Therefore, it has no impact on the ILRT analysis.

Table A-1 List of Finding F&Os on the GGNS Internal Events PRA Model

F&O #	Applicable SR(s)	F&O Details	Resolution	Status	SR CC-II Met/Not Met	Maintenance Update or Upgrade	Importance to Application
		excess conservatism is that the operator action for turning on the H2 igniters was set to 1.0 in the analysis, yet is very significant to the results. Possible Resolution Define severe accident progression sequence and review the results to remove significant conservatisms.	relative contributions to LERF as well as a more detailed comparison of the relative sequence contributions to LERF. The operator action to start the igniters was updated and documented in the HRA Report. The updated HEP was incorporated in the model during the rule-based recovery process. The model was re-quantified and reviewed after changes were made. The igniter operator action identified in the Finding was the only significant conservatism that required refinement. Although the relative importance of hydrogen combustion was reduced, the updated LERF results continue to show that LERF is dominated by containment failures caused by loss of suppression pool cooling and failure of the hydrogen igniters.		independent assessment of finding closure LE-G6: Cat 1-3 MET per independent assessment of finding closure	contributions, and documentation of definitions also did not affect methodology or PRA scope or capability.	
5-13	LE-C1 LE-C2	The approach to the LE analysis was the NUREG/CR-6595 analysis, with a more detailed evaluation of the loss of DHR sequences. Since the Level 1 and LE	The LERF model reviewed by the BWROG Peer Review team double-counted early and late hydrogen events in many of the cutsets which resulted in overestimation of LERF.	Resolved, Closed	LE-C1: Cat 2 MET per BWROG peer review LE-C2: Cat 2 MET per independent	**Maintenance update.** As stated in the finding, the LERF analysis and quantification methodology used conforms to Cat 2.	This finding was closed and the ILRT analysis used the updated model. Therefore, it has no impact on

Table A-1 List of Finding F&Os on the GGNS Internal Events PRA Model

F&O #	Applicable SR(s)	F&O Details	Resolution	Status	SR CC-II Met/Not Met	Maintenance Update or Upgrade	Importance to Application
		results are dominated by loss of DHR, this SR was evaluated as met to Category II. However, the following items are also noted from the peer review: - The Level 1 SR review identified many items that will change the CDF risk results (incorrect IE frequencies utilized, incorrect offsite power recoveries applied, etc.). - The LE results are dominated by containment failure at vessel breach, but the majority of this fraction is hydrogen-related failures of containment. The HEP for turning on igniters was set to 1.0; the peer review team set it to 0.1 in the LERF cutset file (1E-10/yr truncation), and the LERF dropped from 5.81 E-6/yr to 1.74E-6/yr. Because of the peer review team's uncertainty in how the risk profile will change with the identified errors, a finding is developed to ensure the LE analysis is re-examined. If the LE risk	The LERF model was updated to eliminate the double-counting, as verified by LERF cutset reviews. The Level 1 model/data issues identified in other F&Os were corrected as described in those F&Os listed above. A new "Basis for Value" column was added to the LERF basic events table in the LERF Analysis Report to explain the bases for the values used. Updates to the igniter HEPs were performed in the HRA and the values were added to the HRA and LERF Analysis Reports. The model was re-quantified and reviewed after the above changes were made. Although the relative importance of hydrogen combustion was reduced, the updated LERF results continue to show that LERF is dominated by containment failures caused by loss of suppression pool cooling and failure of the hydrogen igniters.		assessment of finding closure	Update of the LERF model and results to address issues in the Level 1 and 2 PRA models, and the updated igniter HEP did not require a change in methodology or PRA scope or capability, but updated insights were obtained.	the ILRT analysis.

Table A-1 List of Finding F&Os on the GGNS Internal Events PRA Model

F&O #	Applicable SR(s)	F&O Details	Resolution	Status	SR CC-II Met/Not Met	Maintenance Update or Upgrade	Importance to Application
		profile changes significantly, then some conservative assessments may require more detailed analysis. Possible Resolution After updating the Level 1 and igniter operation action probability, consider if a more detailed approach to LE is necessary.					
5-14	LE-C2 LE-C4 LE-E1	No credit is given to operator actions in the LE analysis. There is no documentation of a review of GG procedures for potential operator actions to reduce the LERF.	The LERF Analysis Report was updated to document the review of procedures that had previously been performed to identify the operator actions that would be used to respond to the LERF sequence in progress. As part of this review, the systems that could be used by the operators to respond to the scenario had been identified and modeled appropriately. The LERF-related operator actions were evaluated as part of the Human Reliability Analysis. Updates to the igniter HEPs were performed in the HRA and the values were added to the HRA and LERF Analysis Reports.	Resolved, Closed	LE-C2: Cat 2 MET per independent assessment of finding closure LE-C4: Cat 2 MET per BWROG peer review LE-E1: Cat 1-3 MET per BWROG peer review	**Maintenance update.** Enhanced documentation of the process used to identify and model operator actions for LERF sequences did not change the methodology used for the LERF analysis or HRA, or the PRA scope or capability. Nor did the update of the HEP to actuate the igniters.	This finding was closed and the ILRT analysis used the updated model. Therefore, it has no impact on the ILRT analysis.

Table A-1 List of Finding F&Os on the GGNS Internal Events PRA Model

F&O #	Applicable SR(s)	F&O Details	Resolution	Status	SR CC-II Met/Not Met	Maintenance Update or Upgrade	Importance to Application
5-16	LE-D3	Per the containment capacity report (GGNS 92-0034), the failure location with the lowest mean pressure is the basemat (65 psid). The containment failure location was not considered in the LE analysis (all overpressurization was considered a large release, after the 0.5 scrubbing credit for the Auxiliary Building). Since basemat failures could potentially result in underground releases to allow significant scrubbing, the approach taken is conservative. It is noted that other containment failure locations have mean failure pressures that are not much higher than the basemat failures, but some credit could be given to reduce the LERF. [Basis: SR LE-D3 Category II states when containment failure location affects the LERF, define failure location using a realistic assessment.]	The evaluation of containment failure in the updated Success Criteria Report considers the location of the containment failure. The specific locations considered were based on the same design basis Containment performance calculation used to identify the basemat as the weakest point. The LERF analysis does not credit any fission product scrubbing based on Containment Failure location since no approved methodology for crediting scrubbing due to Containment failure location currently exists. There is some probability that the containment failure could be located such that it impacts HPCS operation and the probability of this occurrence was developed in the Calculation of Split Fraction for GGNS ECCS Equipment Given Containment Failure. Additional GOTHIC room heatup analyses were run to evaluate the environment that would be present in the HPCS and LPCS rooms following a Containment failure at a	Resolved, Closed	LE-D3: Cat 2 MET per independent assessment of finding closure	**Maintenance update.** Additional evaluation of containment failure locations did not change the methodology used for the LERF analysis, or the PRA scope or capability. The lack of credit for a decontamination factor for releases has no numerical impact on LERF.	This finding was closed and the ILRT analysis used the updated model. Therefore, it has no impact on the ILRT analysis.

Table A-1 List of Finding F&Os on the GGNS Internal Events PRA Model

F&O #	Applicable SR(s)	F&O Details	Resolution	Status	SR CC-II Met/Not Met	Maintenance Update or Upgrade	Importance to Application
		Possible Resolution Evaluate the potential for containment failures to result in underground releases to potentially remove conservatism from the LERF.	location other than at the basemat.				
5-18	LE-C1 LE-E3	The GG LE analysis does not provide a quantitative definition of 'Large' releases, and does not document the evaluation of sequences as resulting in a 'Early' release. Discussions with the GG PRA team identified that the 'Early' evaluations were based on comparison of MAAP-predicted containment failure time for the dominant sequence (loss of DHR) with the time of declaration of a general emergency. This is acceptable, but the evaluation needs to be documented. [Basis: The LERF contributors from the CSET are all evaluated and carried through the accident progression analysis to the CSET end states. The end states	The new LERF MAAP Analysis Report defines 'Large' and 'Early' releases, documents the results of the LERF MAAP analyses versus the defined criteria, and summarizes the MAAP runs that contribute to LERF.	Resolved, Closed	LE-C1: Cat 2 MET per BWROG peer review LE-E3: Cat 2 MET per independent assessment of finding closure	**Maintenance update.** Enhanced documentation of "large" and "early" release definitions did not change the methodology used for the LERF analysis, or the PRA scope or capability.	This finding was closed and only pertains to documentation. Therefore, it has no impact on the ILRT analysis.

Table A-1 List of Finding F&Os on the GGNS Internal Events PRA Model

F&O #	Applicable SR(s)	F&O Details	Resolution	Status	SR CC-II Met/Not Met	Maintenance Update or Upgrade	Importance to Application
		categorization of LERF or not LERF is not documented, but appears to be reasonable.] Possible Resolution Document a definition of 'Large' releases, and document the evaluation of sequences as resulting in a 'Early' release. The evaluation of 'Large' was qualitative, but appears reasonable (e.g., ISLOCA, Containment Isolation, Containment rupture), but needs to be documented, and the bases should be tied to a quantitative definition of 'Large.'					
5-20	LE-F1 LE-F2 LE-G3	The Quantification notebook (PSA-GGNS-QU-01) presents the total LERF, the top 100 LERF cutsets, and some LERF importance analyses. There is no presentation of the relative contribution to LERF from various contributors other than the importance analysis. Possible Resolution Document the relative contribution to LERF from plant damage states and significant LERF	The Quantification Report was updated to discuss the relative contributions of the LERF sequences, and the Summary Report was updated to provide a comparison of initiating event and other relative contributions to LERF as well as a more detailed comparison of the relative sequence contributions to LERF.	Resolved, Closed	LE-F1, LE-G3: Cat 2-3 MET per independent assessment of finding closure LE-F2: Cat 1-3 MET per independent assessment of finding closure	**Maintenance update.** Enhanced documentation of the LERF results contributions did not change the methodology used for the LERF analysis or quantification, or the PRA scope or capability.	This finding was closed and only pertains to documentation. Therefore, it has no impact on the ILRT analysis.

Table A-1 List of Finding F&Os on the GGNS Internal Events PRA Model

F&O #	Applicable SR(s)	F&O Details	Resolution	Status	SR CC-II Met/Not Met	Maintenance Update or Upgrade	Importance to Application
		contributors from Table 2-2.8-3.					
5-22	LE-G5	Limitations in the analysis have not been identified. The LE analysis should be examined to identify how any simplifying assumptions can impact applications. Possible Resolution Examine the LE analysis to identify how any simplifying assumptions can impact applications.	The Limitations of the LERF analysis were added to the LERF Analysis Report.	Resolved, Closed	LE-G5: Cat 1-3 MET per independent assessment of finding closure	**Maintenance update.** Enhanced documentation of the LERF analysis limitations did not change the methodology used for the LERF analysis, or the PRA	This finding was closed and only pertains to documentation. Therefore, it has no impact on the ILRT analysis.
7-1	IFPP-B3 IFSO-B3 IFSN-B3 IFEV-B3 IFQU-B3	There is no apparent documentation of an uncertainty analysis for any of the following: internal flood plant partitioning; internal flood sources; flood-induced initiating events; accident sequences and quantification Possible Resolution Document the uncertainties in accordance with the standard.	The uncertainty associated with internal flood plant partitioning; internal flood sources; flood-induced initiating events; accident sequences and quantification were added to Internal Flooding Analysis Report. The discussion addresses both aleatory and epistemic (modeling) uncertainty.	Resolved, Closed	IFEV-B3, IFPP-B3, IFQU-B3, IFSN-B3, IFSO-B3: Cat 1-3 MET per independent assessment of finding closure	**Maintenance update.** Enhanced documentation of the uncertainty associated with the IF analysis did not change the methodology used for the IF analysis, or the PRA scope or capability.	This finding was closed and only pertains to documentation. Therefore, it has no impact on the ILRT analysis.

Table A-1 List of Finding F&Os on the GGNS Internal Events PRA Model

F&O #	Applicable SR(s)	F&O Details	Resolution	Status	SR CC-II Met/Not Met	Maintenance Update or Upgrade	Importance to Application
7-2	IFSN-A12 IFSN-A13 IFSO-A3	The EDG building is screened from further analysis based upon a statement in FSAR that "pipe cracks are not postulated inside the diesel generator building;" Possible Resolution Consider spray scenarios for the diesel generator buildings.	The Internal Flooding Analysis Report was updated to provide a more robust basis for screening of the EDG building, based on the inability of a flood within the EDG building to result in a reactor trip since offsite power would not be affected.	Resolved, Closed	IFSN-A12 IFSN-A13, IFSO-A3: Cat 1-3 MET per BWROG peer review	**Maintenance update.** Enhanced documentation of the EDG building screening from the IF analysis did not change the methodology used for the IF flood area screening, or the PRA scope or capability.	This finding was closed and only pertains to documentation. Therefore, it has no impact on the ILRT analysis.
7-4	IFEV-A3	The flood induced initiating event defaults to loss of power conversion system plant initiator (T-2) is conservative. Possible Resolution Run sensitivities to simple turbine trip for comparison power conversion system.	Review of the internal flooding (IF) FRANX database revealed that pipe breaks associated with a loss of a system that results in a reactor trip (e.g., plant service water, circulating water) are actually grouped with the internal events initiator associated with that failed system. Only IF initiators that do not result in a loss of a system that causes a plant trip are grouped with the loss of power conversion system initiating event. This is much more detailed than suggested by the peer review team. The Internal Flooding Analysis Report was updated to better describe the grouping of initiating events and document	Resolved, Closed	IFEV-A3: Cat 1-2 MET per BWROG Peer Review	**Maintenance update.** Enhanced documentation of the IF initiating event grouping did not change the methodology used for the IF quantification, or the PRA scope or capability.	This finding was closed and only pertains to documentation. Therefore, it has no impact on the ILRT analysis.

Table A-1 List of Finding F&Os on the GGNS Internal Events PRA Model

F&O #	Applicable SR(s)	F&O Details	Resolution	Status	SR CC-II Met/Not Met	Maintenance Update or Upgrade	Importance to Application
			the detailed grouping in an appendix.				
7-5	IFQU-A1	It is not evident that accident sequences were performed and documented. There is little evidence contained in RSC-CALKNX-2015- 0803 Possible Resolution Perform and document quantification in accordance with HLR IFQU-A1	The internal flooding model is integrated with the internal events model, and the internal flood accident sequences are quantified using the same methodology as the internal events accident sequences. The Internal Flooding Analysis Report was updated to document the IF accident sequences (formerly included in the PRA Summary Report).	Resolved, Closed	IFQU-A1: Cat 1-3 MET per BWROG Peer Review	**Maintenance update.** Enhanced documentation of the IF accident sequences did not change the methodology used for the internal events or IF sequence quantification, or the PRA scope or capability.	This finding was closed and only pertains to documentation. Therefore, it has no impact on the ILRT analysis.
7-7	IFQU-A1 IFQU-A2 IFQU-A3 IFQU-A4 IFQU-A7 IFQU-A10 IFQU-B1 IFQU-B2	In Table 1, reference to Section 14.0 seems incorrect. Possible Resolution Revise Table 1 as appropriate [IFQU-A7 Basis: it is not evident that the requirements of 2-2.7 were satisfied. For example, no evidence of convergence determination or uncertainty analysis.] [IFQU-B2 Basis: While most are documentation elements satisfied, the is no evidence to support d, results of the IF analysis consistent with HLR-QU-D]	Table 1 (IF "roadmap" for the ASME/ANS PRA requirements) was revised to reference the correct sections and/or other reports as necessary. The updated quantification of the Internal Events PRA and the Internal Flood PRA both now show convergence for both the pre-recovery and the post-recovery cases. A review of the Internal Flood (IF) analysis was performed and documented in the Internal Flooding Analysis Report. This review included cutset reviews for the IF, a review and discussion of the significant IF accident sequences, a review and	Resolved, Closed	IFQU-A1, IFQU-A2, IFQU-A4: Cat 1-3 MET per BWROG Peer Review IFQU-A3: Cat 1-2 MET per BWROG Peer Review IFQU-A7, IFQU-A10 IFQU-B1, IFQU-B2: Cat 1-3 MET per independent assessment	**Maintenance update.** Corrections to the IF "roadmap" for the ASME/ANS PRA requirements, and enhanced documentation of the IF quantification, convergence and results did not change the methodology used for the IF quantification, or the PRA scope or capability.	This finding was closed and only pertains to documentation. Therefore, it has no impact on the ILRT analysis.

Table A-1 List of Finding F&Os on the GGNS Internal Events PRA Model

F&O #	Applicable SR(s)	F&O Details	Resolution	Status	SR CC-II Met/Not Met	Maintenance Update or Upgrade	Importance to Application
			discussion of the significant IF cutsets, and identification of the top IF basic events, HFEs, Maintenance events, CCF events, and initiating events based on Fussell-Vesely and RAW.		of finding closure		
7-8	IFQU-A10	Although it is apparent that quantification of the flooding model was performed as documented in RSC- CALKNX-2015-0803, it is not evident that the LERF analysis was reviewed and documented. Possible Resolution Document the LERF analysis in accordance with IFQU-A10	A review of the Internal Flood (IF) LERF analysis was performed and documented in the Internal Flooding Analysis Report. This review included cutset reviews for the IF LERF, a review and discussion of the significant IF LERF accident sequences, a review and discussion of the significant IF LERF cutsets, and identification of the top IF LERF basic events, HFEs, Maintenance events, CCF events, and initiating events based on Fussell-Vesely and RAW.	Resolved, Closed	IFQU-A10: Cat 1-3 MET per independent assessment of finding closure	**Maintenance update.** Enhanced documentation of the IF LERF results did not change the methodology used for the IF LERF quantification, or the PRA scope or capability.	This finding was closed and only pertains to documentation. Therefore, it has no impact on the ILRT analysis.

A.1.2 Consistency with Applicable PRA Standards

The GGNS PRA model Revision 4b meets the ASME/ANS PRA standard [Reference 49] Capability Category II of the Supporting Requirements (SRs). Current Entergy PRA documentation includes a self-assessment that documents how each high-level requirement (HLR) and SR are met.

The latest full-scope peer review for GGNS was conducted in September 2015 [Reference 53] using the ASME/ANS PRA standard [Reference 49]. Since then, model Revisions 4a and 4b have been completed to address the peer review findings, incorporate some elements of FLEX, and perform additional enhancements [Reference 17]. All the F&Os are captured and documented in the MCR database and the resolution summary report [Reference 54]. No finding level F&Os remain open for the GGNS internal events and internal flooding PRA.

A.2. Seismic PRA

The Seismic PRA results from the IPEEE Seismic Margins Analysis do not result in estimate of CDF [Reference 32]. The seismic CDF values reported in Table D-1 of GI-199 [Reference 34] are used for estimating Seismic CDF in this calculation.

A.3. Fire PRA Model

Grand Gulf Nuclear does not currently have a fire PRA model. The results of the fire risk assessment performed for the IPEEE are used for this analysis, and the risk results are considered reasonable.