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November 15, 2016

Docket Nos.: 50-348
50-364

NL-16-2335

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

Southern Nuclear Operating Company
Joseph M. Farley Nuclear Plant Units 1 and 2;
Re-Submittal of License Amendment Request to Revise
Technical Specification Section 5.5.17 for Permanent
Extension of Type A and Type C Leak Rate Test Frequencies

Ladies and Gentlemen:

On October 4, 2016, Southern Nuclear Operating Company (SNC) submitted a License Amendment Request (LAR) (ADAMS Accession No. ML16280A294) proposing changes to the Unit 1 and Unit 2 Technical Specifications (TS) for extension of Type A and Type C leak rate test frequencies. The risk assessment in that package was erroneously marked as proprietary instead of non-proprietary. The purpose of this submittal is to correct the error and to replace the October 4, 2016 LAR in its entirety.

Therefore, pursuant to 10 CFR 50.90, SNC requests an amendment to the Joseph M. Farley Nuclear Plant (FNP) Unit 1, Renewed Facility Operating License (NPF-2), and Unit 2, Renewed Facility Operating License (NPF-8), by incorporating the attached proposed change into the Unit 1 and Unit 2 TS. Specifically, the proposed change is a request to revise TS 5.5.17 "Containment Leakage Rate Testing Program" to allow the following:

- Increase in the existing Type A integrated leakage rate test (ILRT) program test interval from 10 years to 15 years in accordance with Nuclear Energy Institute (NEI) Topical Report NEI 94-01, Revision 3-A and the conditions and limitations specified in NEI 94-01, Revision 2-A.

- Adopt an extension of the containment isolation valve (CIV) leakage testing (Type C) frequency from the 60 months currently permitted by 10 CFR 50, Appendix J, Option B, to a 75-month frequency for Type C leakage rate testing of selected components, in accordance with NEI 94-01, Revision 3-A.

- Adopt the use of American National Standards Institute/American Nuclear Society (ANSI/ANS) 56.8-2002, Containment System Leakage Testing Requirements.

- Adopt a more conservative grace interval of 9 months, for Type A, Type B and Type C leakage tests in accordance with NEI 94-01, Revision 3-A.

The proposed change to the TS contained herein would revise FNP TS 5.5.17, by replacing the references to Regulatory Guide (RG) 1.163, Performance-Based Containment Leak-Test Program and 10 CFR 50, Appendix J, Option B with a reference to NEI topical report NEI 94-01, Revision 3-A (Reference 2), dated July 2012, and the conditions and limitations specified in NEI 94-01, Revision 2-A dated October 2008, as the documents used by FNP to implement the performance-based leakage testing program in accordance with Option B of 10 CFR 50, Appendix J. This LAR also proposes the following administrative changes to TS 5.5.12:

- Deleting the information regarding the performance of the next FNP Unit 1 and Unit 2 Type A test to be performed during refueling outage R22 for Unit 1 and refueling outage R20 for Unit 2, as both Type A tests have already occurred.

SNC requests approval within 12 months. The proposed changes will be implemented within sixty days of issuance of the amendment.

The Enclosure provides the evaluation of the proposed change and includes attachments with the risk assessment supporting the proposed amendment along with mark-ups of the TS pages and re-typed TS pages.

This letter contains no NRC commitments. If you have any questions, please contact Ken McElroy at 205.992.7369.

Mr. C. R. Pierce states he is the Regulatory Affairs Director for Southern Nuclear Operating Company, is authorized to execute this oath on behalf of Southern Nuclear Operating Company and, to the best of his knowledge and belief, the facts set forth in this letter are true.

Respectfully submitted,

C. R. Pierce

C. R. Pierce
Regulatory Affairs Director

crp/efb/lac

Sworn to and subscribed before me this 15th *day of* November*, 2016.*

Laura L. Crgt
Notary Public

My commission expires: 10-8-2017

Enclosure:
1. Evaluation of Proposed Change

cc: <u>Southern Nuclear Operating Company</u>
Mr. S. E. Kuczynski, Chairman, President & CEO
Mr. D. G. Bost, Executive Vice President & Chief Nuclear Officer
Ms. C. A. Gayheart, Vice President – Farley
Mr. M. D. Meier, Vice President – Regulatory Affairs
Mr. B. J. Adams, Vice President – Engineering
Mr. Mitch Etten-Bohm, Senior Engineer
Ms. B. L. Taylor, Regulatory Affairs Manager – Farley
RType: Farley=CFA04.054

<u>U. S. Nuclear Regulatory Commission</u>
Ms. C. Haney, Regional Administrator
Mr. S. A. Williams, NRR Senior Project Manager – Farley
Mr. P. K. Niebaum, Senior Resident Inspector – Farley

<u>Alabama Department of Public Health</u>
Dr. T. M. Miller, MD, State Health Officer

Southern Nuclear Operating Company
Joseph M. Farley Nuclear Plant Units 1 and 2;
Re-Submittal of License Amendment Request to Revise
Technical Specification Section 5.5.17 for Permanent
<u>Extension of Type A and Type C Leak Rate Test Frequencies</u>

Enclosure

Evaluation of Proposed Change

Southern Nuclear Operating Company

Joseph M. Farley Nuclear Plant Units 1 and 2;

License Amendment Request for Changes to

License Amendment Request to Revise

Technical Specification Section 5.5.12 for Permanent

Extension of Type A and Type C Leak Rate Test Frequencies

EVALUATION OF PROPOSED CHANGE

SUBJECT: Revise Technical Specification 5.5.17 for Permanent Extension of Type A and Type C Leak Rate Test Frequencies

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Attachments:
1. Permanent ILRT Interval Extension Risk Impact Assessment
2. Proposed Technical Specification 5.5.17 (Markup)
3. Re-Typed (Clean-copy) TS page (TS 5.5.17)

1.0 SUMMARY DESCRIPTION

In accordance with 10 CFR 50.90, "Application for amendment of license, construction permit, or early site permit," Southern Nuclear Company (SNC) requests an amendment to Facility Operating License NPF-2 and NPF-8 for Joseph M. Farley Nuclear Plant (FNP), Units 1 and 2, respectively. The proposed change revises Technical Specification (TS) 5.5.17, "Primary Containment Leakage Rate Testing Program," to allow the following:

- Increase the existing Type A integrated leakage rate test (ILRT) program test interval from 10 years to 15 years in accordance with Nuclear Energy Institute (NEI) Topical Report (TR) NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J," Revision 3-A (Reference 1) and the conditions and limitations specified in NEI 94-01, Revision 2-A (Reference 2).

- Adopt an extension of the containment isolation valve (CIV) leakage rate testing (Type C) frequency from the 60 months currently permitted by 10 CFR 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors," Option B, to a 75-month frequency for Type C leakage rate testing of selected components, in accordance with NEI 94-01, Revision 3-A.

- Adopt the use of American National Standards Institute/American Nuclear Society (ANSI/ANS) 56.8-2002, "Containment System Leakage Testing Requirements" (Reference 4).

- Adopt a more conservative allowable test interval extension of nine months, for Type A, Type B and Type C leakage rate tests in accordance with NEI 94-01, Revision 3-A.

Specifically, the proposed change contained herein revises FNP TS 5.5.17, by replacing the references to Regulatory Guide (RG) 1.1.63, "Performance-Based Containment Leak-Test Program," (Reference 1) and 10 CFR Part 50, Appendix J, Option B with a reference to NEI 94-01, Revision 3-A (Reference 2), and the conditions and limitations specified in NEI 94-01, Revision 2-A (Reference 3), as the documents used by FNP to implement the performance-based leakage testing program in accordance with Option B of 10 CFR 50, Appendix J.

This LAR also proposes administrative changes to the exceptions in TS 5.5.17. The exception regarding the performance of the next FNP Type A test, at each unit, to be performed during refueling outage R22 (Spring 2009) for Unit 1 and during refueling outage R20 (Spring 2010) for Unit 2 will be deleted as these Type A tests have already occurred.

2.0 DETAILED DESCRIPTION

FNP TS 5.5.17, "Primary Containment Leakage Rate Testing Program," currently states, in part:

> "A program shall be established to implement the leakage rate testing of 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 in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance Based Containment Leak Test Program," dated September 1995, as modified by the following exception to NEI 94-01, Rev. 0, "Industry Guidelines for Implementing Performance Based Option of 10 CFR 50, Appendix J":

Section 9.2.3: The next Type A test, after the March 1994 test for Unit 1 and the March 1995 test for Unit 2, shall be performed during refueling outage R22 (Spring 2009) for Unit 1 and during refueling outage R20 (Spring 2010) for Unit 2. This is a one-time exception."

The proposed changes to FNP TS 5.5.17 will replace the reference to RG 1.163 with a reference to NEI TR 94-01, Revisions 2-A and 3-A. This LAR also proposes an administrative change to the exception in TS 5.5.17. The exception regarding the performance of the next FNP Type A test, at each unit, to be performed during refueling outage R22 (Spring 2009) for Unit 1 and during refueling outage R20 (Spring 2010) for Unit 2 will be deleted as these Type A tests have already occurred.

The proposed change will revise TS 5.5.17 to state, in part:

> "A program shall be established to implement the leakage rate testing of 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 in accordance with the guidelines contained in NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J," Revision 3-A, dated July 2012, and the conditions and limitations specified in NEI 94-01, Revision 2-A, dated October 2008.

A markup of the proposed change to TS 5.5.17 is provided in Attachment 2. Attachment 3 provides the "clean" retyped TS 5.5.17.

Attachment 1 contains the plant specific risk assessment conducted to support this proposed change. This risk assessment followed the guidelines of NRC RG 1.174, Revision 2 (Reference 6) and NRC RG 1.200, Revision 2 (Reference 7). The risk assessment concluded that the increase in risk as a result of this proposed change is small and is well within established guidelines.

3.0 TECHNICAL EVALUATION

3.1 Description of Primary Containment System

The containment is a pre-stressed, reinforced concrete cylindrical structure with a shallow domed roof and a reinforced concrete foundation slab with provision for a reactor cavity at the center. The cylindrical portion of the containment is pre-stressed by a post-tensioning system composed of horizontal and vertical tendons. The horizontal tendons are placed in three 240-degree segments using three buttresses spaced 120 degrees apart as supports for the anchorages. The dome has a three-way tendon pattern in which groups of tendons intersect at 120 degrees. The concrete foundation is a conventionally reinforced mat. A continuous access gallery is provided beneath the base slab for installation and inspection of the vertical tendons.

A 1/4-inch-thick welded steel liner is attached to the inside face of the concrete. The floor liner is installed on top of the foundation slab and is then covered with concrete. The steel liner plate and penetrations are designed to serve as the leakage barrier for the containment. The design of the liner plate considers the composite action of the liner and the concrete structure and includes the transient effects on the liner due to temperature changes during construction, normal operation, and the loss-of-coolant accident. The changes in strains to be experienced by the liner due to these effects, and those at the pressure testing of the containment, are considered. The

stability of the liner is achieved by anchoring it to the concrete structure. At all penetrations, the liner is thickened to reduce stress concentration. The thickened plate is also anchored to the concrete.

3.1.1 Containment Isolation System

The containment isolation system is in conformance with the NRC acceptance criteria contained in General Design Criteria (GDC) 54, 55, 56, and 57 and RG 1.11 (Reference 8). The general design basis governing isolation valve requirements is as follows:

> *Leakage through all fluid penetrations not serving accident consequence limiting systems is minimized by a double barrier so that no single credible failure or malfunction of an active component results in loss of isolation or intolerable leakage. The installed double barriers take the form of closed piping systems, both inside and outside the containment, and various types of isolation valves.*

Containment isolation in nonessential process lines occurs coincident with the safety injection (SI) actuation signal. Valves, which isolate penetrations that are directly open to the containment, such as the purge valves and sump drain valves, are included in this group. Isolation of valves in essential process lines, such as reactor coolant pump (RCP) cooling, occurs coincident with containment spray (CS) actuation signal.

In accordance with GDC 54, fluid lines penetrating the containment are provided with isolation capability as follows:

Type I — Each line connecting directly to the reactor coolant systems (RCSs) has two CIVs. One valve is located inside the containment and is either an automatic valve, locked closed, or a check valve depending on the direction of normal flow. The second valve is located outside the containment and is either an automatic valve or is locked closed.

Type II — Each line connecting directly to the containment atmosphere has two CIVs. One valve is located inside the containment and is either an automatic valve, is locked closed, or is a check valve, depending on the direction of normal flow. The second valve is located outside the containment and is either an automatic valve or is locked closed.

Type III — Each line that is not directly connected to the RCS nor is open to the containment atmosphere has at least one CIV located outside the containment. This valve is either an automatic valve or is locked closed, or is capable of remote manual operation.

The above isolation valve arrangements have been established to conform to GDC 55, 56, and 57. Fluid instrument lines have been classified in accordance with the design basis given above. Simple check valves are not used as isolation valves outside containment.

3.1.2 Containment Post-Tensioning System

The pre-stressed, post-tensioning system is a low relaxation Inland-Ryerson BBRV button head system using 170 wires of 1/4-in. diameter per tendon. The tendons are installed in metal sheaths, which form ducts through the concrete between anchorage points. Trumpets, which are

enlarged ducts attached to the bearing plate, allow the wires to spread out at the anchorage to suit washer hole spacing and facilitate field button heading of wires. Sheaths are provided with a valved vent at the highest points of curvature to permit release of pockets of entrapped air during greasing operations. Drains are provided at the lowest points of curvature to remove accumulated water prior to installing tendons. In the process of greasing operations, the vents and drains are closed and sealed.

The pre-stressing wire is protected against atmospheric corrosion during its shipment and installation, and during the life of the containment. Prior to shipment, the wire is coated with a thin film of petrolatum containing rust inhibitors. The interior surface of the sheathing is coated with a suitable material during manufacture to minimize removal of the petrolatum from the tendon wires during pulling through the sheathing. The sheathing filler material used for permanent corrosion protection is a modified, refined petroleum oil base product. The material is pumped into the sheathing after stressing.
The vertical tendons are anchored at the top of the ring girder and at the bottom of the foundation slab. The hoop tendons are anchored at buttresses 240 degrees apart, bypassing an intermediate buttress. The anchorages of each successive hoop tendon are progressively offset 120 degrees from the one beneath it. The three-way dome tendons are anchored at the side of the ring girder.

3.1.3 Containment Overpressure on Emergency Core Cooling System (ECCS) Performance

The ECCS is designed so that adequate net positive suction head (NPSH) is provided to system pumps. In addition to considering static head, suction line pressure drop, and debris head loss, the calculation of available NPSH in the recirculation mode assumes that the containment pressure is equal to the TS minimum operating containment pressure prior to the accident (-1.5 pounds per square inch gauge (psig)) for sump temperatures below 206.6 °Fahrenheit (F) (saturation temperature at the minimum TS containment pressure prior to the accident, -1.5 psig or 13.2 psia). Above 206.6 °F, the containment pressure is assumed to be equal to the vapor pressure of the liquid in the sump. These assumptions assure that the actual available NPSH is always greater than the pump required NPSH.

Adequate NPSH is shown to be available for all pumps: Residual Heat Removal (RHR) and Centrifugal Charging Pumps.

Testing has determined that strainer head loss (including debris) decreases as sump temperature increases. The sump fluid is assumed saturated for sump temperatures above the saturation temperature at the TS minimum containment pressure prior to the accident (-1.5 psig). The vapor pressure of the sump inventory decreases significantly as the sump inventory cools below 206.6 °F, while the containment pressure remains in the least margin between available and required NPSH. Therefore, the case which results in the least margin between available and required NPSH for Farley occurs at a sump temperature of approximately 212 °F. There is a negligible difference in NPSH margin at sump temperatures ranging from 206.6 °F to 212 °F. Increased sump temperatures above 212 °F will result in slightly greater NPSH margins based on the strainer head loss testing and constant containment pressure. Strainer head loss is reduced due to the decreased viscosity of water as temperature increases. Above 206.6 °F, NPSH margin will increase due to increased containment pressure and decreased water viscosity.

3.2 Justification for the Technical Specification Change

3.2.1 Chronology of Testing Requirements of 10 CFR Part 50, Appendix J

The testing requirements of 10 CFR Part 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. Title 10 CFR Part 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 (DBA). 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 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 5), 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 8) and Electric Power Research Institute (EPRI) TR-104285 (Reference 9) 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 Safety Evaluation Report (SER) on NEI 94-01 (Reference 10). The NRC SER 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 15 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.

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 15 years. NEI 94-01 has been endorsed as an acceptable methodology for complying with the provisions of 10 CFR 50, Appendix J, Option B by RG 1.163 and NRC SERs dated June 25, 2008, and June 8, 2012 (References 1, 10 and 11, respectively). The regulatory positions stated in RG 1.163, as modified by NRC SERs of June 25, 2008, and June 8, 2012, 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 of 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.

The NRC has provided the following concerning the use of test interval extensions in the deferral of ILRTs past the 15-year interval in NEI 94-01, Revision 2-A, NRC SER Section 3.1.1.2:

> "As noted above, Section 9.2.3, NEI TR 94-01, Revision 2, states, "Type A testing shall be performed during a period of reactor shutdown at a frequency of at least once per 15 years based on acceptable performance history." However, Section 9.1 states that the "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." The NRC staff believes that extensions of the performance-based Type A test interval beyond the required 15 years should be infrequent and used only for compelling reasons. Therefore, if a licensee wants to use the provisions of Section 9.1 in TR NEI 94-01, Revision 2, the licensee will have to demonstrate to the NRC staff that an unforeseen emergent condition exists."

NEI 94-01, Revision 3-A, Section 10.1, Introduction, concerning the use of test interval extensions in the deferral of Type B and Type C LLRTs, based on performance, states, in part,

> "Consistent with standard scheduling practices for Technical Specifications Required Surveillances, intervals of up to 120 months for the recommended surveillance frequency for Type B testing and up to 75 months for Type C testing given in this section may be extended by up to 25% of the test interval, not to exceed nine months.
>
> Notes: For routine scheduling of tests at intervals over 60 months, refer to the additional requirements of Section 11.3.2.
>
> Extensions of up to nine months (total maximum interval of 84 months for Type C tests) are permissible only for non-routine emergent conditions. This provision (nine month extension) does not apply to valves that are restricted and/or limited to 30 month intervals in

Section 10.2 (such as [boiling water reactor] BWR [main steam isolation valves] MSIVs) or to valves held to the base interval (30 months) due to unsatisfactory LLRT performance."

The NRC has also provided the following concerning the extension of ILRT intervals to 15 years in NEI 94-01, Revision 3-A, NRC SER Section 4.0:

> "The basis for acceptability of extending the ILRT interval out to once per 15 years was the enhanced and robust primary containment inspection program and the local leakage rate testing of penetrations. Most of the primary containment leakage experienced has been attributed to penetration leakage and penetrations are thought to be the most likely location of most containment leakage at any time."

3.2.2 Current FNP Primary Containment Leakage Rate Testing Program Requirements

10 CFR 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 September 3, 1996, the NRC approved License Amendment Nos. 122 (Unit 1) and 114 (Unit 2) for FNP (Reference 12) authorizing the implementation of 10 CFR 50, Appendix J, Option B for Types A, B and C tests. Currently, TS 5.5.17 requires that a program be established to comply with the containment leakage rate testing requirements of 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. The program is required to be in accordance with the guidelines contained in RG 1.163. RG 1.163 endorses, with certain exceptions, NEI 94-01, Revision 0, as an acceptable method for complying with the provisions of Appendix J, Option B.

RG 1.163, Section C.1 states that licensees intending to comply with 10 CFR 50, Appendix J, Option B, should establish test intervals based upon the criteria in Section 11.0 of NEI 94-01 (Reference 5) rather than using test intervals specified in American National Standards Institute (ANSI)/American Nuclear Society (ANS) 56.8-1994. NEI 94-01, Section 11.0 refers to Section 9, which states that Type A testing shall be performed during a period of reactor shutdown at a frequency of at least once per ten years based on acceptable performance history. Acceptable performance history is defined as completion of two consecutive periodic Type A tests where the calculated performance leakage was less than $1.0L_a$ (where L_a is the maximum allowable leakage rate at design pressure). Elapsed time between the first and last tests in a series of consecutive satisfactory tests used to determine performance shall be at least 24 months.

Adoption of the Option B performance-based containment leakage rate testing program altered the frequency of measuring primary containment leakage in Types A, B, and C tests but did not alter the basic method by which Appendix J leakage testing is performed. The test frequency is based on an evaluation of the "as found" leakage history to determine a frequency for leakage testing which provides assurance that leakage limits will not be exceeded. The allowed frequency for Type A testing as documented in NEI 94-01 is based, in part, upon a generic evaluation documented in NUREG-1493. The evaluation documented in NUREG-1493 includes a study of the dependence or reactor accident risks on containment leak tightness for differing types of containment types, similar to the Westinghouse-designed containment at FNP. NUREG-1493 concludes in Section 10.1.2 that reducing the frequency of Type A tests (ILRT) from the original three tests per ten years to one test 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 Types B and 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, NUREG-1493 concludes that increasing the interval between ILRTs is possible with minimal impact on public risk.

3.2.3 FNP 10 CFR 50, Appendix J, Option B Licensing History

September 3, 1996 – License Amendment Nos. 122 and 114

The NRC issued Amendment Nos. 122 (FNP-1) and 114 (FNP-2), which modified the TS to reflect the implementation of 10 CFR 50, Appendix J, Option B. (Reference 12)

March 21, 2003 – License Amendment Nos. 159 and 150

The NRC issued Amendment Nos. 159 (FNP-1) and 150 (FNP-2), which revised TS 5.5.17, "Containment Leakage Rate Testing Program." The amendments reflected a one-time deferral of the FNP, Units 1 and 2, Type A Containment ILRT. The 10-year interval between ILRTs was extended to a one-time 15-year interval. (ML030800326) (Reference 13)

3.2.4 Integrated Leakage Rate Testing History (ILRT)

As previously noted, FNP TS 5.5.17 currently requires Types A, B, and C testing in accordance with RG 1.163, which endorses the methodology for complying with Option B. Since the adoption of Option B, the performance leakage rates are calculated in accordance with NEI 94-01, Section 9.1.1 for Type A testing. Tables 3.2.4-1 and 3.2.4-2 list the past FNP-1 and -2 Type A ILRT results.

Table 3.2.4-1, FNP-1 Type A ILRT History

Test Date	Test Results Weight Percent Per Day (wt % / day)	Acceptance Limit (wt % / day)
February, 1977	0.085	0.15
January, 1981	0.054	0.15
April, 1984	0.088	0.15
November, 1986	0.042	0.15
May, 1991	0.055	0.15
March, 1994	0.048	0.15
April, 2009	0.049	0.15

Table 3.2.4-2, FNP-2 Type A ILRT History

Test Date	Test Results (% Weight per Day)	Acceptance Limit (% Weight per Day)
June, 1980	0.061	0.15
March, 1985	0.053	0.15
November, 1987	0.064	0.15
December, 1990	0.048	0.15
March, 1995	0.111	0.15
April, 2010	0.024	0.15

The Type A test acceptance criteria is as follows in accordance with TS 5.5.17:

The peak calculated containment internal pressure for the design basis loss of coolant accident [LOCA], P_a, is 43.8 psig.

The maximum allowable containment leakage rate, L_a, at P_a, is 0.15% of containment air weight per day.

Leakage rate acceptance criteria are:

a. Containment overall leakage rate acceptance criterion is $\leq 1.0\ L_a$. During plant startup following testing in accordance with this program, the leakage rate acceptance criteria are $\leq 0.60\ L_a$ for the combined Type B and C tests, and $\leq 0.75\ L_a$ for Type A tests.

3.3 Plant Specific Confirmatory Analysis

3.3.1 Methodology

An evaluation has been performed to assess the risk impact of extending the FNP ILRT intervals from 10 years to 15 years. The purpose of this analysis is to provide a risk assessment of extending the currently allowed containment Type A Integrated Leak Rate Test (ILRT) interval to a permanent fifteen years for FNP Units 1 and 2. The risk assessment follows the guidelines from NEI 94-01 (Reference 2); the methodology used in EPRI TR 104285 (Reference 9); 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 14); the NRC regulatory guidance on the use of Probabilistic Risk Assessment (PRA) as stated in RG 1.200 as applied to ILRT interval extensions and risk insights in support of a request for a plant's licensing basis as outlined in RG 1.174 (Reference 6); 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 15); and, the methodology used in EPRI 1018243, Revision 2-A of EPRI 109325 (Reference 16).

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 pressurized water reactor (PWR) plant (i.e., Surry), containment isolation failures contribute less than 0.1% to the latent risks from reactor accidents. Consequently, it is desirable to show that extending the ILRT interval will not lead to a substantial increase in risk from containment isolation failures for FNP Units 1 and 2.

NEI 94-01, Revision 2-A contains a final SER that supports using EPRI Topical Report No. 1009325, Revision 2-A, "Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals," for performing risk impact assessments in support of ILRT extensions (Reference 10). The guidance provided in Appendix H of EPRI Report No. 1009325, Revision 2-A 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.

In the SER dated June 25, 2008 (Reference 10), the NRC concluded that the methodology in EPRI TR-1009325, Revision 2, was acceptable for referencing by licensees proposing to amend their TS to extend the ILRT surveillance interval to 15 years, subject to the limitations and

conditions noted in Section 4.0 of the Safety Evaluation (SE). Table 3.3.1-1 addresses each of the four limitations and conditions for the use of EPRI 1009325, Revision 2.

Table 3.3.1-1, EPRI Report No. 1009325 Revision 2 Limitations and Conditions	
Limitation/Condition (From Section 4.2 of SE)	**FNP 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.	FNP PRA technical adequacy is addressed in Section 3.3.2 of this submittal and Attachment 1, "Permanent ILRT Interval Extension Risk Impact Assessment," which addresses the Technical Adequacy of the PRA modeling.
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 core damage frequency (CDF), the relevant criterion is large early release frequency (LERF). The increase in LERF based on the internal events PRA, resulting from a change in the Type A ILRT test interval from three-in-ten years to one-in-fifteen years, is conservatively estimated as 1.75E-07/year for Unit 1 and 1.60E-07/year for Unit 2, using the EPRI guidance. These estimated changes in LERF for FNP Units 1 and 2, while not "very small," are still determined to be within the acceptance guidelines of RG 1.174. [See Attachment 1, Section 7.0 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 change in Type A test frequency to once per fifteen 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 PRA is 1.08E-02 person-rem/year for Unit 1 and 9.89E-03 person-rem/year for Unit 2. EPRI Report No. 1009325, Revision 2-A, states that a very small population dose is defined as an increase of ≤ 1.0 person-rem/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 NRC Final SE for NEI 94-01 and EPRI Report No. 1009325 (Reference 10). Moreover, the risk impact when compared to other severe accident risks is negligible. [See Attachment 1, Section 7.0 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 three in ten year interval to a permanent one time in fifteen-year interval is 0.92% for Unit 1 and 0.92% for Unit 2. EPRI Report No. 1009325, Revision 2-A states that increases in CCFP of ≤ 1.5 percentage points are very small. This is consistent with the NRC Final SE for NEI 94-01 and EPRI Report No. 1009325. Therefore, this increase is judged to be very small. [See Attachment 1 Section 7.0].

Table 3.3.1-1, EPRI Report No. 1009325 Revision 2 Limitations and Conditions	
Limitation/Condition (From Section 4.2 of SE)	**FNP Response**
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 used by FNP is 100 L_a, based on the recommendations in the latest EPRI report (Reference 20) and as recommended in the NRC SE on this topic (Reference 9). It should be noted that this is more conservative than the earlier previous industry ILRT extension requests, which utilized 35 L_a for the Class 3b sequences. [See Attachment 1, Section 3.0]
4. A licensee amendment request (LAR) is required in instances where containment over-pressure is relied upon for emergency core cooling system (ECCS) performance	Adequate NPSH is available to the ECCS pumps assuming the maximum long-term suppression pool temperature with no increase in containment pressure above that present prior to the postulated LOCA. Refer to Section 3.1.3 of this submittal.

3.3.2 Technical Adequacy of the PRA

Technical adequacy of the PRA, synonymous with Probabilistic Safety Assessment (PSA) is presented in Attachment 1, Appendix A, of this submittal.

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

The FNP PRA modeling is highly detailed, including a wide variety of initiating events, modeled systems, operator actions, and common cause failure events. The PRA model quantification process used for the FNP PRA is based on the event tree and fault tree methodology, which is a well-known methodology in the industry.

The FNP PRA model is controlled in accordance with SNC procedure RIE-001, "Generation and Maintenance of Probabilistic Risk Assessment Models and Associated Updates, (Reference 29)" and associated guidelines. This procedure defines the process for implementing regularly scheduled and interim PRA model updates, for tracking issues identified as potentially affecting the PRA models (e.g., due to changes in the plant, errors or limitations identified in the model, industry operating experience, etc.), and for controlling the model and associated computer files. To ensure that the current PRA model remains an accurate reflection of the as-built, as-operated plants, RIE-001 requires that the following activities outlined in the procedure be routinely performed:

- Design changes and procedure changes are reviewed for their impact on the PRA model on an on-going basis
- Reliability data, unavailability data, initiating events frequency data, human reliability data, and other such PRA inputs shall be reviewed approximately every two fuel cycles and updated as necessary to maintain the PRA consistent with the as-operated plant.

Plant Changes Not Yet Incorporated into the PRA Model

As part of the PRA model configuration control, SNC maintains a PRA model maintenance database that tracks all issues that have been identified that could impact the FNP PRA model. The significance of the pending items in the database is evaluated to determine the impact on

model results. Each pending item is prioritized for future model updates according to its significance to model results.

Parts of the PRA Used

The ILRT risk assessment utilizes the overall Level 1 and Level 2 results from Reference 17, as noted in the main report of the ILRT risk assessment. Section 3.2.4.1 of the NRC final SE (Reference 10) of the EPRI ILRT risk assessment methodology documents that Capability Category I is appropriate since approximate values of Core Damage Frequency (CDF) and Large Early Release Frequency (LERF) and their distribution among release categories are sufficient for use in the EPRI methodology.

Risk Assessment Methodology Summary

The ILRT risk assessment methodology is based on EPRI TR-1018243 (Reference 16). The methodology as applied for FNP is fully described in the main report of the ILRT risk assessment.

PRA Key Assumptions and Approximations

For this application, the EPRI methodology involves a bounding approach to estimate the change in LERF for extending the ILRT interval. Rather than exercising the PRA model itself, the methodology involves the establishment of separate calculations that are linearly related to the plant CDF contribution that is not already LERF. The ILRT risk assessment methodology incorporates various assumptions and approximations identified in the main report of the ILRT risk assessment. Key EPRI methodology assumptions and approximations are addressed via sensitivity studies. Any assumptions and approximations utilized in the PRA are judged to have negligible impacts compared to those utilized in the EPRI methodology for the purposes of this application.

Assessment of PRA model Technical Adequacy

Several assessments of technical capability have been made for the FNP Internal Events PRA models:

- An independent PRA peer review was conducted under the auspices of the Westinghouse Owners Group (WOG) in 2001, following the Industry PRA Review process.
- In 2005, a gap analysis was performed against the available version of the ASME PRA Standard (Reference 18) and RG 1.200, Revision 0.

The Farley Unit 1 Probabilistic Risk Assessment (PRA) Peer Review was performed in March of 2010 at the Southern Nuclear offices in Birmingham, AL, using the NEI 05-04 process (Reference 19), the 2009 version of the ASME/ANS PRA Standard (Reference 20), and RG 1.200, Revision 2 (Reference 7). The purpose of this review was to provide a method or establishing the technical adequacy of the PRA for the spectrum of potential risk-informed plant licensing applications for which the PRA may be used.

The 2010 FNP Unit 1 PRA Peer Review was a full-scope review of the Technical Elements of the internals events (including internal flooding), at-power PRA. The PRA reviewed for this Peer Review was the Revision 9 Version 1 of the FNP Unit 1 PRA model.

A summary of the peer review is described in the following information.

- The ASME PRA Standard contains a total of 326 numbered supporting requirements in 14 technical elements and the configuration control element. Of the 326 SRs, eight (8) were determined to be not applicable to the FNP Unit 1 PRA.

- 17 "SR Not Met" have been addressed and closed. Table 1, "Resolution of the Farley PRA Peer Review F&Os Associated with the 17 Not Met SRs," of Attachment 1 of this submittal shows details of the 17 "SR Not Met" findings and resolutions after the peer review.

Conclusion:

The FNP Units 1 and 2 Internal Events PRA model is judged sufficient for the ILRT interval risk-informed application in accordance with RG 1.200, Revision 2.

<u>External Events PRA Quality Statement for Permanent 15-Year ILRT Extension</u>

In addition to the Internal Events PRA models used for this ILRT Risk Assessment, FNP has Fire PRA models for Units 1 and 2, which were developed for Risk Informed applications including National Fire Protection Association Standard 805 (NFPA 805), "Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants, 2001 Edition."

The FNP Fire PRA models underwent a RG 1.200, Revision 2, peer review against the ASME PRA Standard, conducted by the Pressurized Water Reactor Owner's Group (PWROG) in October 2011 in accordance with NEI 07-12. The peer review concluded that the methodologies used in development of the FNP Fire PRA models were appropriate and sufficient to satisfy ASME/ANS PRA Standard RA-Sa-2009. The results of the Fire PRA peer review were included in the LAR submitted to the NRC for approval to transition to NFPA 805 (Reference 21).

In addition to the PWROG peer review, the NRC extensively reviewed the FNP Fire PRA as part of their review and audit of the FNP NFPA 805 LAR submittal. Following their review and approval of the license amendment, the NRC issued an SER (Reference 22), which noted that the disposition and closure of the Fire PRA peer review findings and observations (F&Os) are acceptable.

Based on the results of these reviews, the FNP Fire PRA meets the requirements of the AMSE PRA Standard and therefore is technically adequate and of sufficient quality for use in risk-informed applications. Although not used in the quantitative ILRT Risk Assessment, the Fire PRA CDF and LERF values for Units 1 and 2 are shown in Table 6.2 of Attachment 1 of this submittal, which provides a summary of the contributions of the FNP Internal Events, Fire Events and other External Events models to the total CDF and LERF for each unit.

3.3.3 Summary of Plant-Specific Risk Assessment Results

The findings of the FNP Risk Assessment contained in Attachment 1 confirm the general findings of previous studies that the risk impact associated with extending the ILRT interval from three-in-ten years to one-in-15 years is small. The FNP plant-specific results for extending ILRT interval from the current 10 years to 15 years are summarized below:

Based on the results from Attachment 1 of this submittal, Section 5, "Results," and the sensitivity calculations presented in Attachment 1, Section 6, "Sensitivities," the following conclusions

regarding the assessment of the plant risk associated with permanently extending the Type A ILRT test frequency to fifteen years are:

- RG 1.174, (Reference 6) provides acceptance criteria for increase in CDF and LERF resulting from a risk-informed application. Since the ILRT does not impact CDF, the relevant criterion for this application is LERF. When the calculated increase in LERF is "very small," which is taken as being less than 1.0E-7 per reactor-year, the change will be generally considered acceptable irrespective of the plant's LERF value. When the calculated increase in LERF is in the range of 1.0E-7 per reactor-year to 1.0E-6 per reactor-year, the applications will be considered acceptable only if the total plant LERF is less than 1.0E-5 per reactor-year. The increase in LERF based on the internal events PRA, resulting from a change in the Type A ILRT test interval from three-in-ten years to one-in-fifteen years, is conservatively estimated as 1.75E-07/yr for Unit 1 and 1.60E-07/yr for Unit 2, using the EPRI guidance as written. These estimated changes in LERF for FNP Units 1 and 2, while not "very small," are still determined to be within the acceptance guidelines of RG 1.174, since the plants' LERF values from the internals events PRA are below 1.0E-5 per reactor-year.

- A sensitivity analysis was performed to evaluate the impact of the ILRT application on both internal and external events PRA results. RG 1.174 (Reference 6) states that applications that result in increases to LERF above 1.0E-6 per reactor-year <u>would not normally be considered</u>. <u>Both these values are slightly over the RG 1.174 acceptance criteria value of 1.0E-6. However, as explained in Section 6.3,</u> when the PRA is revised later in 2016 taking credit for the Generation III RCP shutdown seals which are already installed, the plant CDF and LERF values are expected to be significantly lower and similarly the increase in LERF values attributable to ILRT will be considerably lower and below the 1.0E-6 threshold, thus meeting the RG 1.174 criteria.

- According to RG 1.174, although the proposed changes to ILRT do not change the CDF values, <u>no changes would be permitted per this RG if the plant CDF exceeds 1.0E-4 per year. For the sensitivity case of the examination of the impact of external events, the calculated CDF, with the external events included, the CDF for Unit 2 is 1.02E-4 per year, which is slightly higher than this value. However, as explained in Section 6.3,</u> when the PRA is revised later in 2016 taking credit for the Generation III RCP shutdown seals, which are already installed, the plant CDF is expected to be significantly below the 1.0E-4 per year threshold.

- The change in Type A test frequency to once-per-fifteen 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 PRA, is 1.08E-02 person-rem/yr for Unit 1 and 9.89E-03 person-rem/yr for Unit 2. EPRI Report No. 1009325, Revision 2-A states that a very 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. This is consistent with the NRC Final Safety Evaluation for NEI 94-01 and EPRI Report No. 1009325 (Reference 16). Moreover, the risk impact when compared to other severe accident risks is negligible.

- The increase in the conditional containment failure probability from the three-in- ten-year interval to a permanent one time in fifteen-year interval is 0.92% for Unit 1 and 0.92% for Unit 2. EPRI Report No. 1009325, Revision 2-A, states that increases in CCFP of ≤ 1.5 percentage points are very small. This is consistent with the NRC Final SE for NEI 94-01

and EPRI Report No. 1009325 (Reference 16). Therefore, this increase is judged to be very small.

Therefore, permanently increasing the ILRT interval to fifteen years is considered to be a very small change to the FNP Units 1 and 2 risk profiles.

3.3.4 Previous Assessments

The NRC in NUREG-1493 (Reference 8) has previously concluded the following:

- Reducing the frequency of Type A tests (ILRTs) from three per ten years to one per twenty 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 Types B and 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. Beyond testing the performance of containment penetrations, ILRTs also test the integrity of the containment structure.

The findings for FNP confirm these general findings on a plant specific basis considering the severe accidents evaluated for Farley Units 1 and 2, the Farley Units 1 and 2 containment failure modes, and the local population surrounding Farley Units 1 and 2.

Details of the FNP risk assessment are contained in Attachment 1 of this submittal.

3.4 Non-Risk Based Assessment

Consistent with the defense-in-depth philosophy discussed in RG 1.174, FNP has assessed other non-risk based considerations relevant to the proposed amendment. FNP has multiple inspection and testing programs that ensure the containment structure remains capable of meeting its design functions and that are design to identify any degrading conditions that might affect that capability. These programs are discussed below.

3.4.1 Nuclear Coatings Program

The FNP Nuclear Coatings Program performs inspections on coatings in areas inside the reactor containment where coating failure could adversely affect the operation of post-accident fluid systems and, thereby, impair safe shutdown.

The general containment walk-down is performed every outage and completed as soon as possible in the beginning of the outage to ensure that deficient coating areas can be repaired or left in a safe condition prior to start up. After the walk-down, thorough visual inspections are carried out on previously designated areas and on areas noted as deficient during the last inspection. During the inspection, coated surfaces are visually examined for any visible conditions such as blistering, cracking, flaking/peeling, rusting and physical damage. For coating surfaces determined to be suspect, defective or deficient, physical tests such as dry film thickness and adhesion testing may be performed when directed by the evaluator, program engineer/nuclear specialist or program owner.

Unqualified or degraded coatings found during an inspection are documented in the site Unqualified/Degraded Coating Log, which is maintained as a quality record. Areas removed from the Unqualified/Degraded Coating Log will be documented with the reason for removal along with an associated Condition Report or work order (WO).

Unqualified / Degraded Coatings in Containment

The FNP Nuclear Coatings Program requires a log of the amount of unqualified coatings within containment to be maintained. During the most recent FNP-1 coatings inspections performed during the 1R26 refueling outage, the current amount of unqualified coatings reported in the Unqualified Coatings Log is 51.5 square ft against a margin of 856.5 square ft. During the most recent FNP-2 coatings inspections performed during the 2R24 refueling outage, the current amount of unqualified coatings reported in the Unqualified Coatings Log is 13.5 square ft against a margin of 812 square ft.

3.4.2 Containment Inservice Inspection (CISI) Program

The FNP Containment Inservice Inspection Plan provides a summary of the examinations and tests applicable to ASME Code Class CC and MC components for ISI. The plan is currently in the Fourth 10-year interval and was developed utilizing the ASME Section XI Code, 2001 Edition through the 2003 Addenda, Subsections IWE and IWL.

NRC rulemaking dated August 8, 1996, resulted in the first IWE/IWL 10-year interval beginning on September 9, 1998, and ending on September 9, 2008. SNC requested, and subsequently received NRC approval in Reference 33, to align the IWE/IWL interval with the ISI interval, beginning with the Fourth ISI Interval. Therefore, although December 1, 2007, through November 30, 2017, marks the Second Containment IWE/IWL ISI Interval, it will be referred to as the Fourth 10-Year Interval Containment ISI Plan. This had no impact on the scheduling of examinations or tests, and the IWE/IWL Plan was updated to maintain the ASME Section XI Code version consistent for both.

The tendon surveillance program is implemented per ASME Section XI, Subsection IWL. The main features of this program are mentioned below, as described in the Containment Inspection Plan.

a. Subsection IWL specifies the required number of tendons to be examined during an inspection. Both FNP units require a minimum and maximum number of each type of tendon as long as other applicable criteria are met.

b. To develop a history and to correlate the observed data, one tendon from each group should be kept unchanged after the initial selection, and these unchanged tendons should be identified as control tendons.

c. Tendon forces are acceptable if the average of all measured tendon forces for each type of tendon is equal to or greater than the minimum required pre-stress specified at the anchorage for that type of tendon.

Inspection Periods:

IWE

The examinations and tests required by IWA and IWE will be completed during each inspection interval for the service lifetime of the plant. In accordance with ASME Section XI, IWA-2400, FNP has elected to perform these examinations under Inspection Program B of IWA-2400 and IWE-2400. This inspection program is defined as:

- Expedited Examination Period (pre-service/first period of the first interval) from September 9, 1996, to September 8, 2001

- First Containment Inspection Interval – End date modified for the First Containment Inspection Interval to coincide with the end date for the third ISI interval, i.e., November 30, 2007

- Fourth Inspection ISI Interval – The 10 years following the 1st Containment Inspection Interval, i.e., December 1, 2007, to November 30, 2017

- Fifth Inspection Interval – The 10 years following the Second Containment inspection Interval, i.e., December 1, 2017, to November 30, 2027, and

- Sixth Inspection Interval – The 10 years following the Third Containment inspection Interval, i.e., December 1, 2027, to November 30, 2037

NOTE: The first containment inspection interval was to end on September 8, 2008; however, SNC was granted approval to align the containment inspection interval with the ISI interval (Reference 33). The ISI interval and the containment inspection interval were updated and began on December 1, 2007, and the containment interval is now referred to as the Fourth 10-Year Interval Containment ISI Plan.

Reportability Summary:

The following conditions are required to be reported in the ISI Summary Report required by IWA-6000 (Form NIS-1):

- Reference: 10 CFR 50.55a(b)(2)(ix)(A) – If a condition exists in an accessible area for Class MC that could indicate the presence of, or result in, degradation to inaccessible areas, then the report must address: (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.

- Reference: 10 CFR 50.55a(b)(2)(viii)(E) – If a condition exists in an accessible area for Class CC that could indicate the presence of, or result in, degradation to inaccessible areas then the report must address: (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.

The ISI Summary Report (NIS-1 or OAR-1) is required to be submitted to the NRC within 90-days of the end of each RFO. IWL examinations are typically not performed during RFOs. Therefore, any report required by IWL will be included in the ISI Summary Report for the RFO following completion of the IWL examinations.

IWL

The examinations and tests required by IWA and IWL will be completed during each inspection interval for the service lifetime of the plant. The frequency of the concrete containment examination for a particular unit is every 5 years in accordance with IWL-2410(a). The examinations required by IWL-2524 and IWL-2525 shall be performed on a 5-year frequency (±1 year) for the service lifetime of the plant. The examinations required by IWL-2522 and IWL-2523 for a particular unit will be every 10 years.

IWE Components Subject to Examination:

The scope of examinations is based on ASME Section XI, Table IWE-2500-1 and contains the examination category E-A, Containment Surfaces, and E-C, Containment Surfaces Requiring Augmented Examination.

Category E-A, Item E1.10 – Containment Vessel Pressure Retaining Boundary

Components utilized in the design of FNP's Containment are scoped into the IWE Program under item E1.10, which are the accessible surface of the liner and pressure-retaining bolting. These items have been listed out in Tables 3.4.2-1 and 3.4.2-2. Beginning with the 2R21 and the 1R24 outages, FNP included the reactor cavity as part of the IWE scope. Until the spring of 2011, FNP did not include this area in its scope of examinations since it was not understood to be a part of the examination scope. This is discussed in further detail in Section 3.6 of this submittal.

Category E-A, Item E1.30 – Moisture Barriers

Components considered to be part of the moisture barrier are materials that are intended to prevent intrusion of moisture against in accessible areas of the liner plate. The FNP moisture barrier is located along the periphery of containment where the vertical portion of the liner and the concrete fill slab meet on the 105 ft elevation. The moisture barrier is also provided on both sides along the periphery of the secondary shield wall, radially between the outer containment wall and the reactor vessel shield wall, and expansion joints between the fill slab and footings for equipment like the steam generators and RCPs.

Beginning with the 2R23 and 1R26 outages, FNP included the leak chase test connections (LCTCs) as part of the IWE scope. Prior to the spring of 2012, FNP did not have these items scoped under the IWE Program or the Containment Inspection Program; essentially these items were not recognized as a potential location for moisture intrusion to the inaccessible portions of the liner plate. Following the 1R24 outage in spring 2012, the LCTCs were added to the Containment Inspection Plan as an Augmented Examination for both units. Subsequent to the issuance of IN 2014-07 in May 2014, FNP added the LCTCs to the IWE Program as moisture barriers.

Beginning with the 2R23 and 1R26 outages, FNP has scoped in a section of the moisture barrier that was previously excluded from the Containment Inspection Program, but was recognized as a "generic" moisture barrier not under the scope of Subsection IWE. This section of the moisture barrier is sealant that prevents moisture intrusion to inaccessible portions of the liner plate at concrete-to-concrete interfaces. During 2R23, an evaluation was performed to document the need to include this moisture barrier under the scope of IWE. Prior to 2R23 and 1R26, FNP began inclusion of the concrete-to-concrete interfaces under an owner-elected scope based on results of a review performed under a technical evaluation. The review of the containment design

for areas where moisture could make its way to the inaccessible portions of the liner plate failed to identify these concrete-to-concrete expansion joints as potential locations. Additionally, the design drawings for the moisture barrier do not identify a sealant material. A replacement material for the moisture barrier was identified when a section of the moisture barrier needed to be replaced due to damage found during examination. The replacement material was indicated to be Thiokol T-2282.

Unit 1 Containment Inspection Schedule
Table 3.4.2-1 Unit 1 IWE Examination Schedule

Examination Area		December 1, 2007 - November 30, 2010 First Period of the 4th ISI Interval 1R22 / 1R23		December 1, 2010 - November 30, 2014 Second Period of the 4th ISI Interval 1R24 / 1R25		December 1, 2014 - November 30, 2017 Third Period of the 4th ISI Interval 1R26 / 1R27	
Item E1.11 (ASME Table IWE-2500-1) Accessible Surface Areas (Refer to Note 1 of Table 3.4.2-3, Category E-A)	Reactor Cavity Area(3) (Containment liner in the reactor cavity)			1R24(5)(6)		X	
	105' Elevation 0°- 90°(3)	1R22(4)			1R25(9)		X
	105' Elevation 90°- 180°(3)	1R22(4)			1R25(9)		X
	105' Elevation 180° - 270°(3)	1R22(4)			1R25(9)		X
	105' Elevation 270° - 360°(3)	1R22(4)			1R25(9)		X
	129' Elevation 0° - 90°(3)	1R22(4)			1R25(9)		X
	129' Elevation 90° - 180°(3)	1R22(4)			1R25(9)		X
	129' Elevation 180° - 270°(3)	1R22(4)			1R25(9)		X
	129' Elevation 270° - 360°(3)	1R22(4)			1R25(9)		X
	155' Elevation 0° - 90°(3)	1R22(4)			1R25(9)		X
	155' Elevation 90° - 180°(3)	1R22(4)			1R25(9)		X
	155' Elevation 180° - 270°(3)	1R22(4)			1R25(9)		X
	155' Elevation 270° - 360°(3)	1R22(4)			1R25(9)		X
	Above 155' Elevation 0° -90°(3)	1R22(4)		1R24(5)			X
	Above 155' Elevation 90° - 180°(3)	1R22(4)		1R24(5)			X
	Above 155' Elevation 180° - 270°(3)	1R22(4)		1R24(5)			X
	Above 155' Elevation 270° - 360°(3)	1R22(4)		1R24(5)			X
Item E1.11 (ASME Table IWE-2500-1) Pressure Retaining Bolting		VT-3, VT-1 of any bolted connection disassembled		VT-3, VT-1 of any bolted connection disassembled		VT-3, VT-1 of any bolted connection disassembled	
Electrical Penetration Q1T52-B009-A							X(3)
Electrical Penetration Q1T52-B011-B							X(3)
Penetration-14							X(3)
Penetration-71							X(3)
Penetration-72							X(3)
Penetration-90							X(3)
Penetration-92							X(3)

Notes: In addition to the periodic examination required by Item E1.11, 100% of accessible bolted connections must be VT-3 examined, once each interval, per 10CFR50.55a(b)(2)(ix)(G). Flaws or degradation identified during the performance of the VT-3 examination must be examined in accordance with the VT-1 examination method.
Examinations are to be performed when the connection is disassembled but may be performed in place, under tension when disassembly is not otherwise required during the inspection interval. Examination of the bolting for each connection is required only once each inspection interval.

Unit 1 Containment Inspection Schedule Table 3.4.2-1 Unit 1 IWE Examination Schedule							
Examination Area		December 1, 2007 - November 30, 2010 First Period of the 4th ISI Interval 1R22 / 1R23		December 1, 2010 - November 30, 2014 Second Period of the 4th ISI Interval 1R24 / 1R25		December 1, 2014 - November 30, 2017 Third Period of the 4th ISI Interval 1R26 / 1R27	
Item E1.30 (ASME Table IWE-2500-1) Moisture Barriers (Refer to Note 3 of Table 3.4.2-3 Category E-A) (Refer to - Appendix B for information on LCTC location)	Moisture Barrier 0°-360° (Caulking, Flashing and other Sealant)	1R22(4)			X		X
	Leak Chase Test Connection - 1				1R25(9)		X
	Leak Chase Test Connection - 2				1R25(9)		X
	Leak Chase Test Connection - 3			1R24	1R25(9)		X
	Leak Chase Test Connection - 4				1R25(9)		X
	Leak Chase Test Connection - 5			1R24	1R25(9)		X
	Leak Chase Test Connection - 6				1R25(9)		X
	Leak Chase Test Connection - 7				1R25(9)		X
	Leak Chase Test Connection - 8				1R25(9)		X
	Leak Chase Test Connection - 9				1R25(9)		X
	Leak Chase Test Connection - 10				1R25(9)		X
	Leak Chase Test Connection - 11				1R25(9)		X
	Leak Chase Test Connection - 12				1R25(9)		X
	Leak Chase Test Connection - 13				1R25(9)		X
	Leak Chase Test Connection - 14				1R25(9)		X
	Leak Chase Test Connection - 15				1R25(9)		X
	Leak Chase Test Connection - 16				1R25(9)		X
	Leak Chase Test Connection - 17				1R25(9)		X
	Leak Chase Test Connection - 18				1R25(9)		X
	Leak Chase Test Connection - 19				1R25(9)		X
	Leak Chase Test Connection - 20				1R25(9)		X
	Leak Chase Test Connection - 21				1R25(9)		X
	Leak Chase Test Connection - 22				1R25(9)		X
	Leak Chase Test Connection - 23				1R25(9)		X
	Leak Chase Test Connection - 24				1R25(9)		X
	Leak Chase Test Connection - 25				1R25(9)		X
	Leak Chase Test Connection - 26				1R25(9)		X
	Leak Chase Test Connection - 27				1R25(9)		X
	Leak Chase Test Connection - 28				1R25(9)		X
	Leak Chase Test Connection - 29				1R25(9)		X
	Leak Chase Test Connection - 30				1R25(9)		X
	Leak Chase Test Connection - 31				1R25(9)		X
	Leak Chase Test Connection - 32				1R25(9)		X
	Leak Chase Test Connection - 33				1R25(9)		X
	Leak Chase Test Connection - 34				1R25(9)		X
	Leak Chase Test Connection - 35				1R25(9)		X

Unit 1 Containment Inspection Schedule Table 3.4.2-1 Unit 1 IWE Examination Schedule							
Examination Area		December 1, 2007 - November 30, 2010 First Period of the 4th ISI Interval 1R22 / 1R23		December 1, 2010 - November 30, 2014 Second Period of the 4th ISI Interval 1R24 / 1R25		December 1, 2014 - November 30, 2017 Third Period of the 4th ISI Interval 1R26 / 1R27	
Item E1.30 (ASME Table IWE-2500-1) Moisture Barriers (Refer to Note 3 of Table 2.1 Category E-A) (Refer to- Appendix B for information on LCTC location)	Leak Chase Test Connection - 36				1R25(9)		X
	Leak Chase Test Connection - 37				1R25(9)		X
	Leak Chase Test Connection - 38			1R24	1R25(9)		X
	Leak Chase Test Connection - 39				1R25(9)		X
	Leak Chase Test Connection - 40			1R24	1R25(9)		X
	Leak Chase Test Connection - 41				1R25(9)		X
	Leak Chase Test Connection - 42				1R25(9)		X
	Leak Chase Test Connection - 43				1R25(9)		X
	Leak Chase Test Connection - 44				1R25(9)		X
	Leak Chase Test Connection - 45				1R25(9)		X
	Leak Chase Test Connection - 46				1R25(9)		X
	Leak Chase Test Connection - 47				1R25(9)		X
	Leak Chase Test Connection - 48				1R25(9)		X
	Leak Chase Test Connection - 49				1R25(9)		X
	Leak Chase Test Connection - 50				1R25(9)		X
	Leak Chase Test Connection - 51				1R25(9)		X
	Leak Chase Test Connection - 52				1R25(9)		X
	Leak Chase Test Connection - 53				1R25(9)		X
	Leak Chase Test Connection - 54				1R25(9)		X
	Leak Chase Test Connection - 55				1R25(9)		X
	Leak Chase Test Connection - 56				1R25(9)		X
	Leak Chase Test Connection - 57				1R25(9)		X
	Leak Chase Test Connection - 58				1R25(9)		X

NOTES:

(1) Deleted
(2) Scheduled during the last outage of this interval if it has not previously been performed during the interval. Examinations are to be performed when the connection is disassembled; however, they may be performed in place, under tension, when disassembly is not otherwise required during the inspection interval. The VT-3 examination of the bolting is required only once each inspection interval.
(3) Bolted connections that are disassembled during the scheduled General Visual Examinations, must be examined using the VT-3 method. Flaws or degradation identified via the VT-3 examinations must also be examined using the VT-1 method. Material specifications IWB-3517-1 must be used to evaluate the flaws or degradation.
(4) WO 1090680901 provides the full report for the 1R22 IWE evaluations.

(5) WO SNC64083 provides the 1R24 exams.
(6) Perform the General Visual examination of the cavity liner in the RPV sump as proposed by CR 201103645.
(7) Perform the General Visual examination of the Containment leak chase test connections as part of the moisture barrier as required by CAR194863. Examination shall be conducted in accordance with Table IWE-2500-1.
(8) The General Visual of the liner plate in the reactor cavity should be performed at the same time the BMIs of the RPV are performed.
(9) Refer to WO SNC 435880 / SNC 503935 for the full 1R25 IWE report.

Unit 2 Containment Inspection Schedule Table 3.4.2-2 Unit 2 IWE Examination Schedule							
Examination Area		**December 1, 2007 – November 30, 2010 First Period of the 4th ISI Interval 2R19/2R20**		**December 1, 2010 – November 30, 2014 Second Period of the 4th ISI Interval 2R21/2R22/2R23**		**December 1, 2014 – November 30, 2017 Third Period of the 4th ISI Interval 2R24/2R25**	
Item E1.11 (ASME Table IWE-2500-1) Accessible Surface Areas (Refer to Note 1 of Table 2.1, Category E-A)	Reactor Cavity Area(1)(3) (Containment liner in the reactor cavity)(1)(3)(5)(9)			2R21		X	
	105' Elevation 0°- 90°(1)(3)		2R20(5)		2R23(11)		X
	105' Elevation 90°- 180°(1)(3)		2R20(5)		2R23(11)		X
	105' Elevation 180° - 270°(1)(3)		2R20(5)		2R23(11)		X
	105' Elevation 270° - 360°(1)(3)		2R20(5)		2R23(11)		X
	129' Elevation 0° - 90°(1)(3)		2R20(5)		2R23(11)		X
	129' Elevation 90° - 180°(1)(3)		2R20(5)		2R23(11)		X
	129' Elevation 180° - 270°(1)(3)		2R20(5)		2R23(11)		X
	129' Elevation 270° - 360°(1)(3)		2R20(5)		2R23(11)		X
	155' Elevation 0° - 90°(1)(3)		2R20(5)		2R23(11)		X
	155' Elevation 90° - 180°(1)(3)		2R20(5)		2R23(11)		X
	155' Elevation 180° - 270°(1)(3)		2R20(5)		2R23(11)		X
	155' Elevation 270° - 360°(1)(3)		2R20(5)		2R23(11)		X
	Above 155' Elevation 0° -90°(1)(3)		2R20(5)		2R23(11)		X
	Above 155' Elevation 90° - 180°(1)(3)		2R20(5)		2R23(11)		X
	Above 155' Elevation 180° - 270°(1)(3)		2R20(5)		2R23(11)		X
	Above 155' Elevation 270° - 360°(1)(3)		2R20(5)		2R23(11)		X
Item E1.11 (ASME Table IWE-2500-1) Pressure Retaining Bolting		VT-3, VT-1 of any bolted connection disassembled		VT-3, VT-1 of any bolted connection disassembled		VT-3, VT-1 of any bolted connection disassembled	
Electrical Penetration Q2T52-B009-A							X(3)
Electrical Penetration Q2T52-B011-B							X(3)
Penetration-14							X(3)
Penetration-71							X(3)
Penetration-72							X(3)
Penetration-90							X(3)
Penetration-92							X(3)

Notes: In addition to the periodic examination required by Item E1.11, 100% of accessible bolted connections must be VT-3 examined, once each interval, per 10CFR50.55a(b)(2)(ix)(G). Flaws or degradation identified during the performance of the VT-3 examination must be examined in accordance with the VT-1 examination method.

Examinations are to be performed when the connection is disassembled but may be performed in place, under tension when disassembly is not otherwise required during the inspection interval. Examination of the bolting for each connection is required only once each inspection interval.

Unit 2 Containment Inspection Schedule Table 3.4.2-3 Unit 2 IWE Examination Schedule								
Examination Area		December 1, 2007 – November 30, 2010 First Period of the 4th ISI Interval 2R19 / 2R20		December 1, 2010 – November 30, 2014 Second Period of the 4th ISI Interval 2R21/2R22/2R23			December 1, 2014 – November 30, 2017 Third Period of the 4th ISI Interval 2R24/2R25	
Item E1.30 (ASME Table IWE-2500-1) Moisture Barriers (Refer to Note 3 of Table 2.1 Category E-A) (Refer to - Appendix B for information on LCTC location)	Moisture Barrier 0°-360° (Caulking, Flashing and other Sealant)		2R20(5)		2R22(10)			X
	Leak Chase Test Connection - 1				2R22(10)			X
	Leak Chase Test Connection - 2				2R22(10)			X
	Leak Chase Test Connection - 3				2R22(10)			X
	Leak Chase Test Connection - 4				2R22(10)			X
	Leak Chase Test Connection - 5				2R22(10)			X
	Leak Chase Test Connection - 6				2R22(10)			X
	Leak Chase Test Connection - 7				2R22(10)			X
	Leak Chase Test Connection - 8				2R22(10)			X
	Leak Chase Test Connection - 9				2R22(10)			X
	Leak Chase Test Connection - 10				2R22(10)			X
	Leak Chase Test Connection - 11				2R22(10)			X
	Leak Chase Test Connection - 12				2R22(10)			X
	Leak Chase Test Connection - 13				2R22(10)			X
	Leak Chase Test Connection - 14				2R22(10)			X
	Leak Chase Test Connection - 15				2R22(10)			X
	Leak Chase Test Connection - 16				2R22(10)			X
	Leak Chase Test Connection - 17				2R22(10)			X
	Leak Chase Test Connection - 18				2R22(10)			X
	Leak Chase Test Connection - 19				2R22(10)			X
	Leak Chase Test Connection - 20				2R22(10)			X
	Leak Chase Test Connection - 21				2R22(10)			X
	Leak Chase Test Connection - 22				2R22(10)			X
	Leak Chase Test Connection - 23				2R22(10)			X
	Leak Chase Test Connection - 24				2R22(10)			X
	Leak Chase Test Connection - 25				2R22(10)			X
	Leak Chase Test Connection - 26				2R22(10)			X
	Leak Chase Test Connection - 27				2R22(10)			X
	Leak Chase Test Connection - 28				2R22(10)			X
	Leak Chase Test Connection - 29				2R22(10)			X
	Leak Chase Test Connection - 30				2R22(10)			X
	Leak Chase Test Connection - 31				2R22(10)			X
	Leak Chase Test Connection - 32				2R22(10)			X
	Leak Chase Test Connection - 33				2R22(10)			X
	Leak Chase Test Connection - 34				2R22(10)			X
	Leak Chase Test Connection - 35				2R22(10)			X

Unit 2 Containment Inspection Schedule Table 3.4.2-3 Unit 2 IWE Examination Schedule								
Examination Area		**December 1, 2007 – November 30, 2010 First Period of the 4th ISI Interval 2R19 / 2R20**		**December 1, 2010 – November 30, 2014 Second Period of the 4th ISI Interval 2R21/2R22/2R23**			**December 1, 2014 – November 30, 2017 Third Period of the 4th ISI Interval 2R24/2R25**	
Item E1.30 (ASME Table IWE-2500-1) Moisture Barriers (Refer to Note 3 of Table 2.1 Category E-A) (Refer to - Appendix B for information on leak chase test connection location)	Leak Chase Test Connection - 36				2R22(10)			X
	Leak Chase Test Connection - 37				2R22(10)			X
	Leak Chase Test Connection - 38				2R22(10)			X
	Leak Chase Test Connection - 39				2R22(10)			X
	Leak Chase Test Connection - 40				2R22(10)			X
	Leak Chase Test Connection - 41				2R22(10)			X
	Leak Chase Test Connection - 42				2R22(10)			X
	Leak Chase Test Connection - 43				2R22(10)			X
	Leak Chase Test Connection - 44				2R22(10)			X
	Leak Chase Test Connection - 45				2R22(10)			X
	Leak Chase Test Connection - 46				2R22(10)			X
	Leak Chase Test Connection - 47				2R22(10)			X
	Leak Chase Test Connection - 48				2R22(10)			X
	Leak Chase Test Connection - 49				2R22(10)			X
	Leak Chase Test Connection - 50				2R22(10)			X
	Leak Chase Test Connection - 51				2R22(10)			X
	Leak Chase Test Connection - 52				2R22(10)			X
	Leak Chase Test Connection - 53				2R22(10)			X
	Leak Chase Test Connection - 54				2R22(10)			X
	Leak Chase Test Connection - 55				2R22(10)			X
	Leak Chase Test Connection - 56				2R22(10)			X
	Leak Chase Test Connection - 57				2R22(10)			X
	Leak Chase Test Connection - 58				2R22(10)			X

NOTES:

(1) Deleted.
(2) Scheduled during the last outage of this interval if it has not previously been performed during the interval. Examinations are to be performed when the connection is disassembled; however, they may be performed in place, under tension, when disassembly is not otherwise required during the inspection interval. The VT-3 examination of the bolting is required only once each inspection interval.
(3) Bolted connections that are disassembled during the scheduled General Visual Examinations, must be examined using the VT-3 method. Flaws or degradation identified via the VT-3 examinations must also be examined using the VT-1 method. Material specifications IWB-3517/1 must be used to evaluate the flaws or degradation.
(4) Deleted.
(5) WO 2090232401 provides the full report for 2R20 IWE evaluations.
(6) Perform the General Visual examination of the cavity liner in the RPV sump as proposed by CR 201103645.
(7) Perform the General Visual examination of the Containment leak chase test connections as part of the moisture barrier as required by CAR194863. Examination shall be conducted in accordance with Table IWE-2500-1.
(8) Repaired via WO 2053128401 during 2R19.
(9) The General Visual of the liner plate in the reactor cavity should be performed at the same time the BMIs of the RPV are performed.
(10) Refer to WO SNC344240 for 2R22 exams.
(11) Refer to WO SNC390115 for exams performed in 2R23.

IWE Exemption Criteria

Certain Class MC components are exempt from examination. The following criteria will be applied to components exempt from visual and volumetric examination and testing in accordance with ASME Section XI:

Table 3.4.2-4 Exemption Criteria	Reference
Vessels (including RHR and CS encapsulation vessels), parts and appurtenances outside the boundaries of the containment system as defined in the Design Specifications.	IWE-1220
Embedded or inaccessible portions of containment vessels, parts and appurtenances that met the requirements of the original Construction Code.	IWE-1220
Portions of the 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-1220
Piping, pumps and valves that are part of the containment system, or which penetrate or are attached to the containment vessel.	IWE-1220

General Visual Examinations

General visual examinations shall be performed either directly or remotely by line of sight from available viewing angles from floors, platforms, walkways, ladders or other permanent plant vantage points, unless temporary access is required by the inspection plan. The visual examinations shall be performed with adequate illumination sufficient to detect evidence of degradation. Unless otherwise specified, resolution of the VT-2 character card height (0.158 in.) is considered sufficient.

It is SNC's position that a VT-3 visual examination can be performed in lieu of a general visual examination since the criteria for VT-3 are more stringent.

Detailed Visual Examinations

It is SNC's position that a VT-1 visual examination will be performed for a detailed visual examination since the Code is silent on the requirements and allows the Responsible Individual to determine what criteria should be met.

Augmented Examination and Supplemental Examinations

Areas meeting the selection criteria of IWE-1240 will receive augmented examination. Areas may be added as conditions warrant and also may be removed from Augmented Examination status as permitted by IWE-2420(c). Results of augmented examinations in accessible areas will be evaluated for their potential to affect inaccessible areas. The results of this evaluation will determine the scope and extent of augmented examinations in the inaccessible areas.

IWE-1241 requires areas likely to experience accelerated degradation and aging to be subject to the augmented examinations specified in Table IWE-2500-1, Category E-C. Item E4.10 requires detailed visual examination (VT-1) and volumetric examination (UT) of areas exhibiting signs of accelerated degradation of areas having conditions, which could cause accelerated degradation. Currently, there are no areas exhibiting these conditions.

Owner Elected Examinations

No examinations have been identified at this time.

IWL Components Subject to Examination

The scope of examinations is based on ASME Section XI, Table IWL-2500-1 and contains examination categories L-A, Concrete, and L-B, Unbonded Post-Tensioning System.

This testing plan satisfies the programmatic requirements of the following section of the FNP TS:

- 5.5.6, Pre-stressed Concrete Containment Tendon Surveillance Program

L-A Concrete

Item L1.11 requires a General Visual Examination of the accessible exterior concrete surface of the containment building. This examination is required once every five years per IWL-2410.

Accessible grease caps will be inspected during this concrete exam to detect grease leakage or grease cap deformation. In accordance with 10 CFR 50.55a(b)(viii)(A), grease caps will be removed for this examination when there is evidence of tendon and grease cap deformation that indicate deterioration of anchorage hardware.

Item L1.12 requires a detailed visual examination, at the discretion of the Responsible Engineer, of suspect areas that were identified during the general visual examination.

Item L1.12 includes concrete surfaces at tendon anchorage areas.

NOTE: Concrete is pressure tested only after repair and replacement activities (IWL-5210). When pressure tested, it follows the rules of subsection IWE (see IWL-5230).

L-B Unbonded Post-Tensioning System

Item L2.10 requires measurement of the tendon pre-stressing force. Item L2.20 requires removal of a single wire from one tendon of each type for testing. Item L2.30 requires a detailed visual (VT-1) examination of the tendon anchorage components. Items L2.40 and L2.50 require laboratory analysis of the corrosion protection medium including any free water found.

Additional requirements for the post-tensioning system are specified in 10 CFR 50.55a(b)(2)(viii)(E) through (G). Requirements include evaluations of inaccessible areas for degradation when degradation is found in accessible areas that could indicate the presence of degradation in those inaccessible areas. Also, it is indicated that the "owner-identified" qualification provisions in IWL-2310(d) are not approved.

Corrosion protection material must be restored following concrete containment post tensioning system repair and replacement activities in accordance with the quality assurance requirements specified in IWA-1400.

Frequency of 10 years ±1 year
Tendons (Item L2.10)
Tendon wire or strands (Item L2.20)

Frequency of 5 years ±1 year
Tendon anchorages hardware (Item L2.30)
Tendon corrosion protection medium (Item L2.40)
Free Water (L2.50)

Table 3.4.2-5 UNIT 1 ASME IWL EXAMINATION SCHEDULE

REQUIRED EXAMINATIONS CATEGORY	25-YEAR (2002)	30-YEAR (07/2006)	35-YEAR (07/2011)	40-YEAR (07/2016)
L1.11 Accessible Concrete Surface Exams	Aug-02		Jun-12	X
L2.10 and L2.20 Tendon Exams		Mar-06		X
L2.30, L2.40 and L2.50 Anchorage Hardware, Corrosion Protection and Free Water Exams	Aug-02	Mar-06	Jun-12	X

Table 3.4.2-6 UNIT 1 ASME IWL AUGMENTED EXAMINATION SCHEDULE

REQUIRED EXAMINATIONS CATEGORY	1 YEAR (2016) Note 3	5-YEAR (2021)	10-YEAR (2026)	15-YEAR (2031)
L2.10 and L2.20 Tendon Exams	X	X	X	X
L2.30, L2.40 and L2.50 Anchorage Hardware, Corrosion Protection and Free Water Exams	X	X	X	X

Table 3.4.2-7 UNIT 2 ASME IWL EXAMINATION SCHEDULE

REQUIRED EXAMINATIONS CATEGORY	20-YEAR (2000)	25-YEAR (07/2006) Note 1, 2	30-YEAR (07/2011)	35-YEAR (07/2016)
L1.11 Accessible Concrete Surface Exams	Jun-00	Apr-06	Jun-12	X
L2.10 and L2.20 Tendon Exams		Apr-06		X
L2.30, L2.40 and L2.50 Anchorage Hardware, Corrosion Protection and Free Water Exams	Jun-00	Apr-06	Jun-12	X

Notes:
1. In lieu of using the original Structural Integrity Test date to determine when future IWL examinations are required, FNP will utilize a common containment administrative date of July 2006 for both units. The 12-month grace period specified by IWL-2420(c) will be applied to this new common administrative date. (Ref: 3rd 10-Year ISI Interval Relief Request RR-58)
2. FNP committed to complete the Unit 1 30-Year and Unit 2 25-Year IWL Exams by the end of 2006. LC #14422 / LC #14432
3. The 1 Year Exam was permitted to be performed with the Unit 1, 40-Year Exam under NRC SER for FNP-ISI-ALT-14 (ML14169A195).

The 35th and 40th Tendon Surveillance for Farley Unit 1&2 will occur in March 2017. Per ASME Code Subsection IWL-2420(c), the 10 year and subsequent examinations shall commence not more than 1 year prior to the specified dates and shall be completed not more than 1 year after such dates. The Farley tendon surveillance occurs every 5 years in July with a grace period of +/- 1 year which means Farley is abiding with ASME Code Section XI 2001 edition through 2003 addenda, Subsection IWL.

Table 3.4.2-8 Unit 1 Surveillance Tendon Selection (Prior to ASME IWL Requirements)

Surveillance	Date	Vertical Tendons	Dome Tendons			Hoop Tendons		
ONE YEAR	Jun-78	V16 V39 V66 V95 V116	D114 D123	D202 D230	D309 D317	H1AB H6AB H12AB H17AB H24AB H32AB	H29BC H39BC	H25CA H36CA
THREE-YEAR	Aug-80	V16 V27 V86 V105 V126	D107 D122	D227 D231	D309 D324	H6AB H12AB H26AB H29AB H39AB	H36BC H39BC	H25CA H30CA H36CA
THREE-YEAR (RESURVEILLANCE)	Jun-82	V16 V27 V86 V105 V126	D107 D122	D227 D231	D309 D324	H6AB H12AB H26AB H29AB H39AB	H36BC H39BC	H25CA H30CA H36CA
FIVE-YEAR	Jun-82	V5 V18 V60 V100 V128	D110 D119	D203 D229	D303 D319	H8AB H14AB H36AB	H25BC H33BC H40BC	H18CA H20CA H38CA H44CA
TEN-YEAR	Sep-87	V14 V31 V72 V109 V120	D121	D228	D320	H2AB	H44BC	H26CA
FIFTEEN-YEAR	Jul-92	V61 V99 V113	D110	D201	D318	H42AB	H18BC	H27CA
TWENTY-YEAR	May-97	V1 V43 V80	D102 D118		D311	H3AB	H26BC	H42CA

Table 3.4.2-9 Unit 1 Surveillance Tendon Selection (ASME IWL Requirements)								
Surveillance	Date	Vertical Tendons	Dome Tendons			Hoop Tendons		
TWENTY FIVE-YEAR	Aug-02	V1* V47 V101	D111	D202	D322	H41AB	H26BC	H13CA
THIRTY-YEAR	Mar-06	V1* V70 V104	D116	D202*	D313	H33BA	H26BC*	H35CA
THIRTY FIVE YEAR	Jun-12	V1* V54 V115 V104	D118	D202*	D321	H4AC	H26BC* H39BC	H35BA
FORTY-YEAR								
FORTY FIVE-YEAR								
FIFTY-YEAR								
FIFTY FIVE-YEAR								

Table 3.4.2-10 Unit 2 Surveillance Tendon Selection (Prior to ASME IWL Requirements)								
Surveillance	Date	Vertical Tendons	Dome Tendons			Hoop Tendons		
ONE YEAR	Aug-81	V16 V39 V66 V95 V116	D114 D123	D202 D229 D230 D231	D308 D309 D310 D317	H12DE H33DE H43DE	H2FD H8FD H18FD H24FD	H2EF H7EF H18EF
THREE-YEAR	Sep-83	V20 V27 V76 V103 V127	D107 D130	D225 D227	D302 D322	H4DE H9DE H44DE	H1FD H14FD H34FD	H19EF H25EF H29EF H39EF
FIVE-YEAR	Sep-85	V4 V28 V52 V79 V100	D109 D117 D119	D227	D307 D319	H1DE H21DE H28DE H45DE	H13FD H26FD H42FD	H3EF H17EF H31EF
TEN-YEAR	Jul-90	V28 V55 V71 V92 V11	D102	D217	D327	H16DE	H10FD	H35EF
FIFTEEN-YEAR	Aug-95	V36 V60 V119	D104 D122	D220 D231	D312	H5DE	H37FD	H27EF

Table 3.4.2-11 Unit 2 Surveillance Tendon Selection (ASME IWL Requirements)								
Surveillance	Date	Vertical Tendons	Dome Tendons			Hoop Tendons		
TWENTY-YEAR	Jun-00	V16* V63 V108	D114*	D124	D304	40DE	15EF	24FD*
TWENTY FIVE-YEAR	Apr-06	V16* V61 V118	D114* D113** D115**	D201	D318	8DE	30EF	24FD*
THIRTY-YEAR	Jun-12	V16* V57 V121	D114*	D226	D316	H18DE	H34EF H39BC	H24FD*
THIRTY FIVE-YEAR								
FORTY-YEAR								
FORTY FIVE-YEAR								
FIFTY-YEAR								
FIFTY FIVE-YEAR								

Table 3.4.2-12 Unit 1 IWL Surveillance Record

ITEM NO.	CAT. NO	EXAM DESCRIPTION	METHOD[1]	INITIAL	25-YEAR	30-YEAR	35-YEAR[2] (2011)	40-YEAR[2] (2016)
L1.11	L-A	Room 241- 155' Elevation	VT-3C	Jun-00	August-02	February-06	June-12	
		Room 429 - 155' Elevation	VT-3C	Jun-00	August-02	February-06	June-12	
		Room 409 - 155' Elevation	VT-3C	Jun-00	August-02	February-06	June-12	
		Room 418 - 155' Elevation	VT-3C	Jun-00	August-02	February-06	June-12	
		Room 478 - 155' Elevation	VT-3C	Jun-00	August-02	February-06	June-12	
		Room 241 - 139' Elevation	VT-3C	Jun-00	August-02	February-06	June-12	
		Room 334 - 139' Elevation	VT-3C	Jun-00	August-02	February-06	June-12	
		Room 333 - 139' Elevation	VT-3C	Jun-00	August-02	February-06	June-12	
		Room 347 - 139' Elevation	VT-3C	Jun-00	August-02	February-06	June-12	
		Room 332 - 139' Elevation	VT-3C	Jun-00	August-02	February-06	June-12	
		Room 241 - 121' Elevation	VT-3C	Jun-00	August-02	February-06	June-12	
		Room 223 - 121' Elevation	VT-3C	Jun-00	August-02	February-06	June-12	
		Room 237 - 121' Elevation	VT-3C	Jun-00	August-02	February-06	June-12	
		Room 194 - 100' Elevation	VT-3C	Jun-00	August-02	February-06	June-12	
		Room 189 - 100' Elevation	VT-3C	Jun-00	August-02	February-06	June-12	
		Room 184 - 100' Elevation	VT-3C	Jun-00	August-02	February-06	June-12	
		Room 183 - 100' Elevation	VT-3C	Jun-00	August-02	February-06	June-12	
		Room 182 - 100' Elevation	VT-3C	Jun-00	August-02	February-06	June-12	
		Room 172 - 100' Elevation	VT-3C	Jun-00	August-02	February-06	June-12	
		Room 186 - 100' Elevation	VT-3C	Jun-00	August-02	February-06	June-12	
		Room 131 - 77' & 83' Elevation	VT-3C	Jun-00	August-02	February-06	June-12	
		Room 129 - 77' & 83' Elevation	VT-3C	Jun-00	August-02	February-06	June-12	
		Room 125 - 77' & 83' Elevation	VT-3C	Jun-00	August-02	February-06	June-12	
		Room 111 - 77' & 83' Elevation	VT-3C	Jun-00	August-02	February-06	June-12	
L1.11	L-A	Containment Outside Surfaces 0° to 90°	VT-3C	Jun-00	August-02	February-06	June-12	
		Containment Outside Surfaces 90° to 180°	VT-3C	Jun-00	August-02	February-06	June-12	
		Containment Outside Surfaces 180° to 270°	VT-3C	Jun-00	August-02	February-06	June-12	
		Containment Outside Surfaces 270° to 360°	VT-3C	Jun-00	August-02	February-06	June-12	
		Tendon Access Gallery 0° to 90°	VT-3C	Jun-00	August-02	February-06	June-12	

ITEM NO.	CAT. NO	EXAM DESCRIPTION	METHOD[1]	INITIAL	25-YEAR	30-YEAR	35-YEAR[2] (2011)	40-YEAR[2] (2016)
		Tendon Access Gallery 90° to 180°	VT-3C	Jun-00	August-02	February-06	June-12	
		Tendon Access Gallery 180° to 270°	VT-3C	Jun-00	August-02	February-06	June-12	
		Tendon Access Gallery 270° to 360°	VT-3C	Jun-00	August-02	February-06	June-12	
		Containment Dome	VT-3C	Jun-00	August-02	February-06	June-12	

ITEM NO.	CAT. NO	EXAM DESCRIPTION	METHOD[1]	20-YEAR	25-YEAR	30-YEAR	35-YEAR[3] (2011)	40-YEAR[3] (2016)
L2.10	L-B	Tendon	IWL-2522	Jun-97		March-06		X
L2.20		Wire	IWL-2523.2	Jun-97		March-06		X
L2.30		Anchorage Hardware and Surrounding Concrete	Detailed Exam VT-1 & VT-1C	Jun-97	August-02	March-06	Jun-12	X
L2.40		Corrosion Protection Medium	IWL-2525.2(a)	Jun-97	August-02	March-06	Jun-12	X
L2.50		Free Water	IWL-2525.2(b)	Jun-97	August-02	March-06	Jun-12	X

ITEM NO.	CAT. NO	EXAM DESCRIPTION	METHOD[1]	1 YEAR[1] (2016)	5-YEAR[1] (2021)	10-YEAR[1] (2026)	15-YEAR[3] (2031)	20-YEAR[3] (2036)
L2.10	L-B	Tendon	IWL-2522	X	X	X	X	X
L2.20		Wire	IWL-2523.2	X	X	X	X	X
L2.30		Anchorage Hardware and Surrounding Concrete	Detailed Exam VT-1 & VT-1C	X	X	X	X	X
L2.40		Corrosion Protection Medium	IWL-2525.2(a)	X	X	X	X	X
L2.50		Free Water	IWL-2525.2(b)	X	X	X	X	X

Exemption Criteria

Certain Class CC components are exempt from IWL-2000 examinations, however, 10 CFR 50.55a(b)(2)(viii)(E) may require additional evaluation and reporting. The following criteria will be applied to exempt components from examination in accordance with ASME Section XI:

Table 3.4.2-13 Exemption Criteria	Reference
Tendon end anchorages that are inaccessible. However, these applicable anchorages are still subject to requirements of IWL-2521.1	IWL-1220(a)
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.	IWL-1220(b)

Technical Specification Requirements

This testing plan satisfies the programmatic requirements of the following section of the FNP TS:

- 5.5.6, Pre-stressed Concrete Containment Tendon Surveillance Program

Augmented Examination Requirements Following Post-Tensioning System Repair/Replacement Activities

On May 3, 2012, Farley experienced a catastrophic failure on the field end anchor head of horizontal tendon H7AB. A root cause investigation occurred and attributed the failure to Hydrogen Stress Cracking (HSC). The actual root cause was identified as being a lack of monitoring additional tendon grease parameters beyond the current ASME Section XI IWL Code required parameters, which were adhered to by FNP, in order to identify adverse conditions that could lead to anchor head failure.

Actions stemming from the root cause involved sampling tendon anchorages for deficient grease, which resulted in the need to perform magnetic particle testing on some anchor heads and anchor head replacement for some tendons. As a result of the root cause investigation, several anchor heads were replaced due to the potential for similar tendon failure occurring on all three categories of tendons, those being hoop, dome and vertical. Anchor head replacements were required to be performed under a Design Change since a slightly different material with a lower Rockwell C (Rc) hardness number was chosen for the replacement anchor heads. The replacement anchor heads are identical in design to the previously installed anchor heads, except that the replacement anchor heads were manufactured with a lower RG hardness number to provide improved resistance to hydrogen embrittlement failure. A total of fifteen different tendons from Units 1 and 2 were affected by the anchor head replacement activities. The failed tendon, H7AB on Unit 1, was completely replaced. The other fourteen tendons were temporarily de-tensioned, the field end anchor head replaced, and subsequently re-tensioned.

Long-term actions stemming from the root cause involved monitoring additional parameters during grease sampling, which was incorporate into the Farley Tendon Surveillance procedures. In addition, a one-time monitoring requirement for the grease must be performed during the Unit 1 40th year and Unit 2 35th year surveillances, which were also added to the Farley Tendon Surveillance procedures.

The following tendons were affected by the repair/replacement activity.

Table 3.4.2-14 Tendon Replacement Activity Summary

Unit	Tendon ID	Configuration	Activity
1	H7AB	Hoop	Anchor head replacement and Tendon replacement
1	H25AC	Hoop	Anchor head replacement
1	H27AC	Hoop	Anchor head replacement
1	H28BC	Hoop	Anchor head replacement
1	H29AB	Hoop	Anchor head replacement
1	H30AC	Hoop	Anchor head replacement
1	H33AB	Hoop	Anchor head replacement
1	H35AB	Hoop	Anchor head replacement
1	H41AB	Hoop	Anchor head replacement
1	H44AB	Hoop	Anchor head replacement
1	D322	Dome	Anchor head replacement
2	H5DE	Hoop	Anchor head replacement
2	D220	Dome	Anchor head replacement
2	D231	Dome	Anchor head replacement
2	V60	Vertical	Anchor head replacement

Since the above tendons were affected by a repair/replacement activity, they are now required to be tested in accordance with Table IWL-2521-2.

Per Table IWL-2521-2, the lesser of 4% of the affected tendons or ten tendons is the required sample size when the number of affected tendons is greater than or equal to 5% of the total tendon population. If less than 3 tendons are affected, then there is no required sample size for augmented examinations. The following table has been added to help clarify and explain FNP's requirements for examination.

Table 3.4.2-15 Augmented Tendon Examinations

Unit & Type of Tendon	Total No. of Tendons in Population Type	5% of Tendon Type Population (Rounded)	No. of Tendons Affected by R/R	Required Sample Size
U1 Horizontal	135	7	10	1
U1 Vertical	130	7	0	N/A
U1 Dome	93	6	1	N/A
U2 Horizontal	134	7	1	N/A
U2 Vertical	130	7	1	N/A
U2 Dome	93	5	2	N/A

Since the number of horizontal tendons on Unit 1 affected by the repair/replacement activities (ten) is greater than 5% of the total, the required sample size per Table IWL-2521-2 is one horizontal tendon (i.e., the lesser of 4% of the affected tendons or ten tendons). No other type of tendon meets the threshold, as can be seen in Table 3.4.2-15 above.

In accordance with Table IWL-2521-2, the initial inspection following the completion of the repair/replacement activity is to be performed 1 year (± 3 months) from completion of the repair/replacement activity. The repair/replacement activity began in December 2012 and

concluded in September 2013. Since only 1 of the affected tendons actually requires examination in the following year, FNP requested an alternative to delay examination of the 1 tendon. This alternative was submitted to the NRC under FNP-ISI-ALT-14, "Joseph M. Farley Nuclear Plant Unit 1, Proposed Alternative for the Fourth Interval Inservice Inspection (FNP-ISI-ALT-14, Version 1.0," (ML14050A382) (Reference 30). SNC requested that the examination of the Unit 1 tendons, be deferred to the next regularly scheduled examination, which is currently planned for 2016. After some additional questions from the NRC, the alternative was approved as documented in the NRC SER, "Joseph M. Farley, Unit 1 Alternative Request Regarding Containment Building Tendon Examination Schedule (TAC No. MF3488)," dated July 11, 2014 (ML14169A195) (Reference 31).

During the Forty-Year Tendon Surveillance, currently scheduled to occur during 2016, one of ten horizontal Unit 1 tendons affected by the repair/replacement activity will need to be examined along with the normal scope of tendon examinations. As in accordance with Table IWL-2521-2, once the initial inspection following the repair/replacement activity has occurred, examination of the tendons affected by the repair/replacement activity will be examined in a schedule to coincide with the remaining population.

3.4.3 Supplemental Inspection Requirements

With the implementation of the proposed change, TS 5.5.17 will be revised by replacing the reference to RG 1.163 (Reference 1) with reference to NEI 94-01, Revision 3-A (Reference 2). This will require that a general visual examination of accessible interior and exterior surfaces of the containment for structural deterioration that may affect the containment leak-tight integrity be conducted. This inspection must be conducted prior to each Type A test and during at least three other outages before the next Type A test if the interval for the Type A test has been extended to 15 years in accordance with the following sections of NEI 94-01, Revision 3-A:

• Section 9.2.1, "Pretest Inspection and Test Methodology"
• Section 9.2.3.2, "Supplemental Inspection Requirements"

In addition to the IWE examinations scheduled in accordance with the Containment Inservice Inspection Program, the performance of inspections per the Containment Leakage Rate Testing Program, will be utilized to ensure compliance with the visual inspection requirements of TS SR 3.6.1.1, SR 3.6.1.2 and NEI 94-01, Revision 3-A.

3.4.4 Results of Recent Containment Examinations

Results of Recent IWE Examinations

<u>1R25 Refueling Outage</u>

1R25 examinations were performed under the direct supervision of responsible IWE engineering personnel. Most of the areas had been observed, noted and evaluated in previous general and VT-3 examinations.

The following were the reported conditions and engineering recommendations:

Indication 1 noted approximately 29 inches of intermittent scratches with some gouges 1/2 in. to 3/4 in. long x 1/8 in. wide. The gouges were all 1/16 in. deep or less, located near 195 degrees at 159 ft elevation. Engineering analysis of the degraded liner plate showed a

minimum thickness of 1/32 in. is acceptable as long as it serves the function of a leak tight barrier. Therefore, the conditions identified were determined to not have any adverse affect on the performance of the liner membrane. The indications were recoated during the 1R26 refueling outage.

Indication 2 noted tack welds on liner plate to support test bars, located near 270 degrees at 160 ft elevation. There is no rust on the tack welds. The exposed welds were recoated during 1R26.

Indication 3 noted approximately 30 inches of intermittent scratches with some gouges 1/2 in. to 3/4 in. long x 1/8 in. wide. The gouges were all 1/32 in. deep or less, located near 195 degrees at 159 ft elevation. Engineering analysis of the degraded liner plate showed a minimum thickness of 1/32 in. is acceptable as long as it serves the function of a leak tight barrier. Therefore, the conditions identified were determined to not have any adverse affect on the performance of the liner membrane. The indications were recoated during the 1R26 refueling outage.

Indication 8 noted miscellaneous scratches, with bare metal exposed. There was no rust on the scratches. The scratches were approximately 12 in. long and 3/8 in. wide, with no measurable depth. This indication is located on the east side of containment, 4 ft. to the left of the polar crane ladder and 12 ft below the polar crane. The identified areas were recoated during 1R26.

Indication 11 noted scratches on the liner approximately 30 in. long by 3/4 in. wide, exposing the bare metal liner. The scratches are located at 38 degrees and 146 ft elevation. There was no rust. The identified areas were recoated during 1R26.

Indication 12 noted a scratch 8 in. long by 1 in. wide, exposing bare metal. There is no rust. The scratch is located at 35 degrees and 130 ft elevation. The identified areas were recoated during 1R26.

Indication 13 noted a small gouge approximately 2 in. long and 1/32 in. deep. The gouge is located near 140 degrees at elevation 106 ft. Engineering analysis of the degraded liner plate showed a minimum thickness of 1/32 in. is acceptable as long as it serves the function of a leak tight barrier. Therefore, the conditions identified were determined to not have any adverse affect on the performance of the liner membrane. The indications were recoated during the 1R26 refueling outage.

Indication 14 noted moisture barrier functional, but degraded at the intersection of the floor and the liner plate, near leak chase port #55 on the 105 ft elevation. There is no evidence of moisture penetration. A new section of moisture barrier was installed at Indication 14 during 1R26.

Indication 15 noted a 3 ft section of moisture barrier that is functional, but degraded, located at 163 degrees, elevation 105 ft. There is no evidence of moisture penetration. A new section of moisture barrier was installed at Indication 15 during 1R26.

Indication 16 noted an area of moisture barrier that is functional, but degraded, located at between 250 degrees to 272 degrees. There is no evidence of moisture penetration. A new section of moisture barrier was installed at Indication 16 during 1R26.

Indication 17 noted several scratches 5 to 6 in. long by 1 to 2 in. wide, exposing the bare metal liner. There was no rust. The scratches are located at 105 degrees and elevation 115 ft. The identified areas were recoated during 1R26.

Indications 18, 19, 20 & 21 noted heavy wear to the liner plate around penetrations 35, 41, 82, and 83. The bare metal liner was exposed, with slight surface rust. The identified areas were recoated during 1R26.

Indication 22 noted scraping to the exposed liner plate approximately 5 in. long. There is no visible rust. The scrape is located at 58 degrees and elevation 116 ft. The identified areas were recoated during 1R26.

Indication 23 noted flaking paint to the exposed liner plate approximately 2 in. long. There is no visible rust. The flaking is located at 60 degrees and elevation 108 ft. The identified areas were recoated during 1R26.

Indication 24 noted scraping to the exposed liner plate approximately 8 in. long. There is no visible rust. The scrape is located at 130 degrees and elevation 116 ft. The identified areas were recoated during 1R26.

Indication 25 noted scrapes to the exposed liner plate approximately 10 in. long. There is no visible rust. The scraping is located near 194 degrees and elevation 105 ft nearest the floor. The identified areas were recoated during 1R26.

Indication 26 noted an area of moisture barrier (approximately 3 to 4 ft) that is functional, but degraded, located near 284 degrees. There is no evidence of moisture penetration. A new section of moisture barrier was installed at Indication 26 during 1R26.

<u>1R26 Refueling Outage – Spring 2015</u>

During 1R26, a first time examination of the moisture barriers used in the expansion joints located radially around the containment floor between the containment wall, bioshield wall and the steam generator and RCP platforms was conducted. Prior to this examination, these locations were incorrectly excluded from the scope of the FNP Containment Inservice Inspection Program. Additionally, a first time examination of the leak chase channels that served as moisture barriers was conducted in response to NRC Information Notice (IN) 2014-07.

During the examination, several areas of degraded moisture barrier were identified. Levels of degradation varied from portions of the moisture barrier missing completely, to evidence of cracking of the moisture barrier and lack of adhesion to the concrete surface. In the areas of missing sealant, the one-half inch of compressible material below the sealant was still in place. Much of the sealant was still pliable to touch and still adhered to either side of the joint, but at the locations of degraded sealant it was easily pushed down or pulled away. At four locations of missing sealant throughout containment, standing water was found at varying depths with dirt/sludge material at the bottom with two having depth to obtain chemistry samples. These locations were both inside and outside the bioshield wall at expansion joints in the floor and at the floor-to-wall expansion joint.

All accessible LCTC floor covers were removed to inspect for the condition of the pipe port. During the examination, the covers were removed to look at the pipe cap to pipe connection, which serves as a moisture barrier. Following cover removal, liquid was discovered in two of

the recessed portions of the LCTCs (Nos. 4 and 23). Two LCTCs' pipes and pipe caps were completely corroded through (Nos. 10 and 52). The conditions observed prompted pipe cap removal on forty-seven additional locations, of which thirty-one locations were noted to have varying levels of moisture in the pipe.

UT measurements were performed on the inaccessible portion of the containment liner plate. One UT location was on a portion of the liner plate located in one of the wetted expansion joints, the other two locations were underneath leak chase channels at LCTC Nos. 6 and 45. All three examinations were performed with results that were repeatable and acceptable. Nominal liner plate thickness at these locations is 1/4-inch. The three locations examined had thickness measurements of 0.25 inches, 0.30-0.32 inches, and 0.35 inches, respectively.

In addition to the ultrasonic (UT) examinations, numerous visual inspections were performed. All locations with missing expansion joint sealing were visually inspected for evidence of liquid and to inspect the bottom of the expansion joints. However, the inability to completely remove the liquid, grit and silt in the joint resulted in the inability to perform a qualified or unqualified visual examination of the liner.

<u>2R23 IWE Examination Results</u>

Liner Examination

All accessible surfaces in all four containment liner quadrants were examined during 2R23. The following conditions were noted:

The liner at elevation 105 ft was examined from the south wall of the fuel transfer canal around to the north wall of the fuel transfer canal. Three areas of interest were noted. Disposition of the areas showed the results of the examination to be acceptable.

The liner at elevation 129 ft was examined from the south wall of the fuel transfer canal around to the north wall of the fuel transfer canal. Two areas of interest were noted. Disposition of the areas showed the results of the examination to be acceptable.

Three areas were observed where the paint was flaking and/or cracking. Additionally, one area was observed approximately 9 ft to the right of the equipment hatch. The area was 8 to 10 ft above the 155 ft elevation and had scraped paint. The area of interest was approximately 18 inches square. No rust or pitting was observed.

A piece of metal, which appeared to be previously welded to the liner plate, was discovered at the 333 azimuth location just behind the polar crane platform rail and above the operator's platform. This was identified in the initial IWE inspection. Engineering indicated that this is a known defect with no concern for degradation of the liner integrity.

Moisture Barrier Examination

During 2R23, several areas of degraded moisture barrier were identified. Levels of degradation varied from portions of the moisture barrier missing completely, cracking of the moisture barrier and a lack of adhesion to the concrete surface. Much of the sealant was still pliable to the touch and still adhered to either side of the joint. However, at locations where the sealant was degraded, the sealant was easily pushed down or pulled away. At twelve locations of missing sealant throughout containment, standing water was found at varying depths with dirt/sludge

material at the bottom. These locations were both inside and outside the bioshield wall at expansion joints in the floor and at the floor to wall expansion joint (not including the periphery of containment).

As a result of the identified degradation of the moisture barrier, the provisions of ASME Section XI, Subsection IWE were invoked to assess the condition of the inaccessible portion of the liner plate to ensure containment integrity had been maintained. UT thickness examinations at three locations on the containment liner plate showed no evidence of loss of material. An engineering evaluation was completed prior to the conclusion of the 2R23 RFO that evaluated the UT thickness data and determined the containment liner's leak-tight integrity was still intact and acceptable for at least one more operating cycle.

In addition to the moisture barrier examinations, all LCTC floor covers were removed to inspect the condition of the port. During the examination of the LCTCs, the covers for the LCTCs were removed to look at the pipe cap to pipe connection (moisture barrier). Liquid was discovered in two of the recessed portions of the LCTC. One LCTC did not have a pipe cap installed and another LCTC's pipe and pipe cap were completely corroded through. The conditions were assessed after all initial examinations were performed. Further investigation into the LCTC resulted in the removal of the pipe cap on 51 locations of which 20 locations were noted to have varying levels of moisture in them. The remaining locations were noted as being dry. In addition, when the pipe cap on LCTC 50 was removed, liquid was observed flowing out of the pipe for a short time. A video probe was utilized to look inside the LCTCs that had their pipe caps removed.

2R24 IWE Examination Results

During 2R24, an examination was performed on the containment moisture barrier along with the reactor pressure vessel sump liner. The examination found various areas of staining throughout the examination area. Two areas of flaking coatings were observed which were previously identified during the 2R21 RFO and have not changed. Various areas of minor blistered and chipped coatings were observed. No corrosion or degradation was observed on uncoated areas of liner plate. One unidentified leak chase port was observed.

Results of Recent IWL Examinations

Unit 1 35th Year / Unit 2 30th Year Examination – Containment Structure Post Tensioning System

The 2012 tendon surveillance at Farley Nuclear Plant began on April 30, 2012 and was completed on June 7, 2012. This examination satisfied the requirements for the Unit 1 35th Year and Unit 2 30th Year examinations of the Containment Structure Post Tensioning System. The tendon surveillance program consists of a periodic inspection of the condition of a selected group of tendons. This surveillance period consisted of a visual inspection of the post tensioning system. A visual tendon surveillance consists of: sheathing filler inspection and testing, inspection for water, anchorage inspection, concrete inspection around tendons, and replacement of grease after completion of all inspections. Ten (10) tendons on Unit 1 and nine (9) tendons on Unit 2 were selected for inspection during the tendon surveillance. These tendons are termed "Original Scope Tendons."

The results of the examinations were as follows:

IWL-3221 Acceptance by Examination

IWL-3221.3 Tendon Anchorage Areas: *The condition of tendon anchorage areas is acceptable if:*

(a) *there is no evidence of cracking in anchor heads, shims or bearing plates*

Results: Detailed inspections did not reveal any cracks in the anchorage components for any inspected tendon end.

(b) *there is no evidence of active corrosion;*

Results: The field end of Unit 1 hoop tendon H35AB revealed corrosion Level C. This was reported in NCR FN1078-002. No other tendon end inspected revealed active corrosion on the anchorage components.

(c) *broken on unseated wires, broken strands, and detached buttonheads were documented and accepted during a pre-service examination or during a previous in-service examination;*

Results: During the examination of surveillance tendon ends, missing or protruding wires/buttonheads were discovered on three (3) tendons on Unit 1 and three (3) tendons on Unit 2 that were not previously reported.

(d) *cracks in the concrete adjacent to the bearing plates do not exceed 0.01 in (3mm) in width;*

Results: No cracks exceeding 0.010 in. were detected in the 24 in. of concrete adjacent to the bearing plates of the tendon ends inspected.

(e) *there is no evidence of free water*

Results: No water was observed during the cap removal of any inspected tendon.

IWL-3222 Acceptance by Evaluation. *Items with examination results that do not meet the acceptance standards of IWL-3221 shall be evaluated as required by IWL-3300.*

Results: All conditions that did not meet the corresponding inspection criteria were documented, evaluated and deemed acceptable via Farley Plant Action Report process.

Based upon the evaluation of the ISI results for the 2012 Farley Nuclear Plant Containment Building Tendon Surveillance report, the containment structures have experienced no abnormal degradation of their post-tensioning system.

2012 Containment Concrete General Visual Examination

During the 2012 containment structure post tensioning systems tendon surveillance, the general visual examination of the FNP-1 and FNP-2 concrete surfaces was performed in accordance with ASME Section XI, Subsection IWL. The results are as follows:

Unit 1 Tendon Gallery

Information Only Indications: Water leakage into tunnel at tunnel wall exterior below containment basemat; oil seeping around grease caps and inlet plugs.

Reportable Indications: Surface rusting of grease cap bolts

Disposition by Responsible Engineer: Conditions are acceptable. Similar conditions recorded during 2006 IWL Inspection.

Unit 1 Containment Dome

Reportable Indications: Concrete spalling greater than 8 in.; passive cracks greater than 0.030 in.; rail embeds rusting and staining concrete, form tie grout patches

Disposition by Responsible Engineer: Conditions are acceptable. Similar conditions recorded during 2006 IWL Inspection.

Unit 1 Buttress A Face

Information Only Indications: Small cracks greater than 0.010 in.; small bug holes

Reportable Indications: Small spalls greater than 6 in.; form tie grout patches

Disposition by Responsible Engineer: Conditions are acceptable. Similar conditions recorded during 2006 IWL Inspection.

Unit 1 Buttress B Face

Information Only Indications: Small cracks greater than 0.010 in.; small bug holes

Reportable Indications: Small spalls greater than 6 in.; form tie grout patches; spall on edge of buttress with dimensions 18 by 18 by 2 in. deep, grout patch observed to be loose

Disposition by Responsible Engineer: Conditions are acceptable. Similar conditions recorded during 2006 IWL Inspection. Grout patch is scheduled to be repaired by December 2017.

Unit 1 Buttress C Face

Information Only Indications: Small cracks greater than 0.010 in.; small bug holes; small spalls; form tie grout patches

Disposition by Responsible Engineer: Conditions are acceptable. Similar conditions recorded during 2006 IWL Inspection.

Unit 1 Between Buttress A and Buttress B

Information Only Indications: Small bug holes; form tie grout patches; cracks greater than 0.010 in.

Reportable Indications: Grease leak out of crack in construction pour line greater than 0.010 in.

Disposition by Responsible Engineer: Conditions are acceptable. Similar conditions recorded during 2006 IWL Inspection.

Unit 1 Between Buttress B and Buttress C

Information Only Indications: Small bug holes; form tie grout patches; cracks greater than 0.010 in.

Reportable Indications: Grease leak out of crack in construction pour line greater than 0.010 in., 4 ft from buttress B between tendons H17BC and H16BC, grease leak was active though minimal; grease leak out of crack in construction pour line greater than 0.010 in., 2 ft from buttress C by tendon H43CB, appears to be inactive; grease leak out of grease inlet plug in concrete above bearing plate of H27BC at buttress B, old grease running down buttress to bottom, inactive leak; grease leak out of grease cap inlet plug (old, inactive) on tendon H44CB at buttress C and running down to H41CB at buttress C

Disposition by Responsible Engineer: Conditions are acceptable. Similar conditions recorded during 2006 IWL Inspection.

Unit 1 Between Buttress C and Buttress A

Information Only Indications: Small bug holes; form tie grout patches; cracks greater than 0.010 in.

Reportable Indications: Grease leaking out of crack in construction pour line greater than 0.010 in. 25 ft from buttress A and 25 ft up from roof, old grease, inactive; grease leak out of crack in construction pour line greater than 0.010 in. 35 ft from buttress A and 35 ft up from roof, old grease, inactive; grease leak out of crack in construction pour line greater than 0.010 in., 20 ft from buttress C and 25 ft up from roof, old grease, inactive

Disposition by Responsible Engineer: Conditions are acceptable. Similar conditions recorded during 2006 IWL Inspection.

Unit 1 Ring Girder – Buttress B to Buttress C

Information Only Indications: Small bug holes; form tie grout patches;

Reportable Indications: Passive cracks greater than 0.030 in.; efflorescence from rail anchor pads; small spalls around dome tendon pocket edges greater than 6 in.

Disposition by Responsible Engineer: Conditions are acceptable. Similar conditions recorded during 2006 IWL Inspection.

Unit 1 Ring Girder – Buttress A to Buttress B

Information Only Indications: Small bug holes; form tie grout patches

Reportable Indications: Passive cracks greater than 0.030 in.; efflorescence from rail tie anchor pads; small spalls around dome tendon pocket edges greater than 6 in.

Disposition by Responsible Engineer: Conditions are acceptable. Similar conditions recorded during 2006 IWL Inspection.

Unit 1 Ring Girder – Buttress C to Buttress A

Information Only Indications: Small bug holes; form tie grout patches;

Reportable Indications: Passive cracks greater than 0.030 in.; efflorescence from rail tie anchor pads; small spalls greater than 6 in. around dome tie tendon pocket edges

Disposition by Responsible Engineer: Conditions are acceptable. Similar conditions recorded during 2006 IWL Inspection.

Unit 1 Room 184 – 100 ft Elevation

Reportable Indications: Grease leaking out of inlet plug in concrete above H5BC C Buttress running down to bottom of buttress

Disposition by Responsible Engineer: Plug scheduled to be tightened by December 2017.

Unit 1 Room 332 – 139 ft Elevation

Reportable Indications: Grease leaking out of inlet plug on K22AB A Buttress running down to bottom of buttress

Disposition by Responsible Engineer: Plug scheduled to be tightened by December 2017.

Unit 2 Tendon Gallery

Information Only Indications: Water leaking into tunnel at tunnel interior wall below basemat

Reportable Indications: Oil seepage around grease inlet plugs; grease cap bolts show surface rust

Disposition by Responsible Engineer: Conditions are acceptable. Similar conditions recorded in prior IWL inspection (2006).

Unit 2 Dome

Reportable Indications: Small spalls greater than 6 in.; passive cracks greater than 0.030 in.; form tie grout patches; rail embeds rusting and staining concrete

Disposition by Responsible Engineer: Conditions are acceptable. Similar conditions recorded in prior IWL inspection (2006). Dome coating and rail system scheduled to be repaired by December 2017.

Unit 2 Buttress D Face

Information Only Indications: Small cracks greater than 0.010 in.; small bug holes

Reportable Indications: Small spalls; form tie grout patches

Disposition by Responsible Engineer: Conditions are acceptable. Similar conditions recorded in prior IWL inspection (2006).

Unit 2 Buttress E Face

Information Only Indications: Small cracks greater than 0.010 in.; small bug holes

Reportable Indications: Small spalls greater than 6 in.; form tie grout patches

Disposition by Responsible Engineer: Conditions are acceptable. Similar conditions recorded in prior IWL inspection (2006).

Unit 2 Buttress F

Information Only Indications: Small cracks greater than 0.010 in.; small bug holes

Reportable Indications: Small spalls greater than 6 in.; form tie grout patches

Disposition by Responsible Engineer: Conditions are acceptable. Similar conditions recorded in prior IWL inspection (2006).

Unit 2 Between Buttress D and E

Information Only Indications: Small bug holes; small cracks greater than 0.010 in.

Reportable Indications: Form tie grout patches; grease leak out of crack greater than 0.010 in. in construction pour line, active through minimal above top left corner of equipment hatch

Disposition by Responsible Engineer: Conditions are acceptable. Similar conditions recorded in prior IWL inspection (2006).

Unit 2 Between Buttress E and Buttress F

Information Only Indications: Small bug holes; small cracks greater than 0.010 in.

Reportable Indications: Form tie grout patches

Disposition by Responsible Engineer: Conditions are acceptable. Similar conditions recorded in prior IWL inspection (2006).

Unit 2 Between Buttress F and Buttress D

Information Only Indications: Small bug holes; small cracks greater than 0.010 in.

Reportable Indications: Form tie grout patches

Disposition by Responsible Engineer: Conditions are acceptable. Similar conditions recorded in prior IWL inspection (2006).

Unit 2 Ring Girder – Buttress D to Buttress E

Information Only Indications: Small bug holes; form tie grout patches

Reportable Indications: Passive cracks greater than 0.030 in.; efflorescence from rail anchor pads; small spalls greater than 6 in. around dome tendon pocket edges

Disposition by Responsible Engineer: Conditions are acceptable. Similar to conditions recorded in prior IWL inspection (2006).

Unit 2 Ring Girder – Buttress E to Buttress F

Information Only Indications: Small bug holes; form tie grout patches

Reportable Indications: Passive cracks greater than 0.030 in.; efflorescence from rail anchor pads; small spalls greater than 6 in. around dome tendon pocket edges

Disposition by Responsible Engineer: Conditions are acceptable. Similar to conditions recorded in prior IWL inspection (2006).

Unit 2 Ring Girder – Buttress F to Buttress D

Information Only Indications: Small bug holes; form tie grout patches

Reportable Indications: Passive cracks greater than 0.030 in.; efflorescence from rail anchor pads; small spalls greater than 6 in. around dome tendon pocket edges

Disposition by Responsible Engineer: Conditions are acceptable. Similar conditions recorded in prior IWL inspection (2006).

Unit 2 Room 2429 – Elevation 155 ft

Surface of concrete painted – no indications noted

Reportable Indications: Grease leaking out of H21EF inlet grease plug in concrete. Grease running down buttress to H17EF.

Disposition by Responsible Engineer: Conditions are acceptable. Similar conditions recorded in prior IWL inspection (2006).

Unit 2 Room 2184 – Elevation 100 ft

Reportable Indication: Grease leaking through concrete crack greater than 0.010 in. in line with M1FE, 1 ft from buttress (active leak)

Disposition by Responsible Engineer: Conditions are acceptable. Similar to conditions recorded in prior IWL inspection (2006).

Containment Coating Assessments

1R25 Containment Coatings Assessment

The 1R25 Containment Coatings Assessment was performed between March 30 through April 21, 2015. The following results were documented.

Coating identification and resolution are those that appear in Section 3.4.4, Results of Recent IWE Examinations – 1R25 Refueling Outage.

2R24 Containment Coatings Assessment

During 2R24, an assessment of the containment coatings was performed. The following results were documented.

Flaking paint found on liner wall of containment at 155 ft elevation, azimuth 236 approximately 12 inches by 18 inches. This location was recoated during 2R24 with Amercoat 90N coating.

3.4.5 Containment Leakage Rate Testing Program - Type B and Type C Testing Program

FNP Types B and C testing program requires testing of electrical penetrations, airlocks, hatches, flanges and CIVs in accordance with 10 CFR 50, Appendix J, Option B and RG 1.163 (Reference 1). 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. In accordance with TS 5.5.17, the allowable maximum pathway total Types B and C leakage is 0.6 L_a (140,862 standard cubic centimeters per minute (sccm)) where L_a equals approximately 234,771 sccm.

As discussed in NUREG-1493 (Reference 8), Type B and Type C tests can identify the vast majority of all potential containment leakage paths. Type B and Type C testing will continue to provide a high degree of assurance that containment integrity is maintained.

A review of the As-Found (AF) / As-Left (AL) test values for FNP Unit 1 and Unit 2 can be summarized as:

- FNP Unit 1 As-Found minimum pathway leak rate shows an average of 11.33% of 0.6 L_a with a high of 14.68% of 0.6L_a.
- FNP Unit 1 As-Left maximum pathway leak rate shows an average of 14.31% of 0.6 L_a with a high of 26.55% of 0.6 L_a.
- FNP Unit 2 As-Found minimum pathway leak rate shows an average of 13.42% of 0.6 L_a with a high of 22.31% of 0.6L_a.
- FNP Unit 2 As-Left maximum pathway leak rate shows an average of 22.12% of 0.6 L_a with a high of 41.08% of 0.6 L_a.

Tables 3.4.5-1 and 3.4.5-2 provide local leak rate test (LLRT) data trend summaries for FNP Units 1 and 2 since 2006. This summary demonstrates a history of satisfactory Type B and Type C tested component performance from the Spring of 2006 through the Spring of 2015,

inclusive of the ILRT performed in 2009 for Unit 1 and from the Fall of 2006 through the Fall of 2014 inclusive of the ILRT performed in 2010 for Unit 2.

Table 3.4.5-1 FNP Unit 1 Types B and C LLRT Combined As-Found / As-Left Trend Summary							
Year & RFO	2006	2007	2009	2010	2012	2013	2015
	1R20	1R21	1R22	1R23	1R24	1R25	1R26
AF Min Path (SCCM)	20,675.84	7,732.66	16,325.76	18,834.77	12,734.72	17,738.61	17,755.86
Fraction of 0.6 L_a (percent)	14.68%	5.49%	11.59%	13.37%	9.00%	12.59%	12.61%
AL Max Path (SCCM)	24,261.35	5,602.69	20,190.58	13,509.42	24,853.24	37,404.85	14,625.93
Fraction of 0.6 L_a (percent)	17.22%	3.98%	14.33%	9.59%	17.64%	26.55%	10.83%
AL Min Path (SCCM)	19,496.60	11,789.09	15,056.72	8,475.38	13,485.55	10,378.62	8,119.58
Fraction of 0.6 L_a (percent)	13.84%	8.37%	10.69%	6.02%	9.57%	7.37%	5.76%

Table 3.4.5-2 FNP Unit 2 Types B and C LLRT Combined As-Found / As-Left Trend Summary							
Year & RFO	2007	2008	2010	2011	2013	2014	2016
	2R18	2R19	2R20	2R21	2R22	2R23	2R24
AF Min Path (SCCM)	31,429.70	11,551.67	15,949.27	16,079.54	21,487.82	9,245.2	33,346.84
Fraction of 0.6 L_a (percent)	22.31%	8.20%	11.32%	11.42%	15.25%	6.56%	18.94%
AL Max Path (SCCM)	28,713.40	21,287.70	20,781.6	19,405.10	34,372.30	35,752.3	72,333.2
Fraction of 0.6 L_a (percent)	20.38%	15.04%	14.75%	13.78%	24.40%	25.38%	41.08%
AL Min Path (SCCM)	20,708.80	10,878.97	14,106.12	13,822.90	21,594.92	18,441.85	31,171.85
Fraction of 0.6 L_a (percent)	14.70%	7.72%	10.01%	9.81%	15.33%	13.09%	17.70%

Type B and Type C Local Leak Rate Testing Program Implementation Review

There were no administrative limit failures associated with components on extended intervals identified in RFOs 1R25 or 1R26 for FNP Unit 1. However, the components that were on extended LLRT intervals and have not demonstrated acceptable performance during the previous two outages for FNP Unit 2 are identified in Table 3.4.5-3.

Table 3.4.5-3 FNP Unit 2 Type B and C LLRT Program Implementation Review						
2R23 - Fall 2014						
Component	As-Found SCCM	Admin Limit SCCM	As-Left SCCM	Cause of Failure	Corrective Action	Scheduled Interval
Q2G21HV337	870	800	870	Note 1	Note 1	30 Months
2R24 - Spring 2016						
Component	As-Found SCCM	Admin Limit SCCM	As-Left SCCM	Cause of Failure	Corrective Action	Scheduled Interval
Q2P16V081	1695	1410	1695	Note 2	Note 2	30 Months

Note 1: This component was accepted for continued service without rework or repair. The total contribution of the As-Left Penetration 78 maximum pathway leakage is 4.26% of 0.6 L_a. Overall, there was approximately a 75% margin between the As-Left maximum pathway totals and 0.6 L_a during 2R23. Q2G21HV337 is scheduled for replacement during the 2R25 RFO.

Note 2: This component was accepted for continued service without rework or repair. Q2P16V081 is the inboard CIV for FNP-2 Penetration 32. Measured leakage on the outboard CIVs 2QP16V072 and 2QP16V203 had observed leakage at 516 sccm. A maximum pathway leakage rate of 516 sccm was assigned to the penetration. Q2P16V081 is scheduled for repair during the 2R25 RFO.

Statistics on Number of Components on Extended Intervals

Unit 1:

The percentage of the total number of FNP-1 Appendix J Type B tested components that are on 120-month extended performance-based test intervals is approximately 83%.

The percentage of the total number of FNP-1 Appendix J Type C tested components that are on 60-month extended performance-based test intervals is approximately 83%.

Unit 2:

The percentage of the total number of FNP-2 Appendix J Type B tested components that are on 120-month extended performance-based test intervals is approximately 88%.

The percentage of the total number of FNP-2 Appendix J Type C tested components that are on 60-month extended performance-based test intervals is approximately 90%.

3.5 Operating Experience

During the conduct of the various examinations and tests conducted in support of the containment related programs previously mentioned, issues that do not meet established criteria or that provide indication of degradation, are identified, placed into the site's corrective action program, and corrective actions are planned and performed.

For the FNP Primary Containment, the following site specific and related industry events have been evaluated for impact on the FNP Primary containment:

- IN 89-79, "Degraded Coatings and Corrosion of Steel Containment Liners"
- IN 92-20, "Inadequate Local Leak Rate Testing"
- IN 96-13, "Potential Containment Leak Paths Through Hydrogen Analyzers"
- IN 99-10, "Degradation of Pre-stressing Tendon Systems in Pre-stressed Concrete Containments"
- IN 2004-09, "Corrosion of Steel Containment and Containment Liner"
- IN 2010-12, "Containment Liner Corrosion"
- IN 2014-07, "Degradation of Leak-Chase Channel Systems for Floor Welds of Metal Containment Shell and Concrete Containment Metallic Liner"
- Regulatory Issue Summary (RIS) 2016-07, "Containment Shell or Liner Moisture Barrier Inspection"
- Operating Experience Report (OER) OE32389, "Containment Liner Through-Wall Degradation at Turkey Point-3 in.
- OER OE31696, "Concrete Containment Delamination Exposed during Steam Generator Replacement (SGR) Hydro-Excavation at Crystal River 3 in.

Each of these areas is discussed in detail in Sections 3.5.1 through 3.5.10, respectively.

3.5.1 IN 89-79, "Degraded Coatings and Corrosion of Steel Containment Liners"

NRC IN 89-79 and Supplement 1 address coating damage and corrosion of the steel ice condenser containment vessels at two BWR facilities. Ice condenser-type containment vessels consist of a freestanding steel shell surrounded by a concrete shield building. Between the steel shell and the concrete shell there is an annular air space. Coating damage and corrosion occurred on the outer surface of the steel shell and was caused by boric acid and collected condensation on the floor of the annular space between the steel shell and the surrounding concrete shield building. Coating damage and corrosion also occurred on the inside surface at the floor level in a 2-inch floor gap filled with cork that interfaces with the coated steel containment. The cork contains moisture originating from the ice condenser or from condensation.

Discussion

FNP has a post-tensioned concrete containment structure. The FNP containment structures do not have an annulus such as described in this IN. Even though the FNP containment structures have an interior steel liner, there is no space between the liner and the concrete. The accessible portions of this linear are visually inspected every 40 months in conjunction with the containment integrated leak rate test and no corrosion problems have been found. Therefore, no further action is required with regard to this notice.

3.5.2 IN 92-20, "Inadequate Local Leak Rate Testing"

The NRC issued IN 92-20 to alert licensees of problems with local leak rate testing of two-ply stainless steel bellows used on piping penetrations at four different plants: Quad Cities, Dresden Nuclear Station, Perry Nuclear Plant, and the Clinton Station. Specifically, LLRTs 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 the problem. The common issue in the four events was the failure to adequately perform local leak rate testing on different penetration configurations leading to problems that were discovered during ILRT tests in the first three cases.

In the event at Quad Cities, the two-ply bellows design was not properly subjected to LLRT pressure and the conclusion of the utility was that the two-ply bellows design could not be Type B LLRT tested as configured.

In the events at both Dresden and Perry, flanges were not considered a leakage path when the Type C LLRT test was designed. This omission led to a leakage path that was not discovered until the plant performed an ILRT test.

In the event at Clinton, relief valve discharge lines that were assumed to terminate below the suppression pool minimum drawdown level were discovered to terminate at a level above that datum. These lines needed to be reconfigured and the valves should have been Type C LLRT tested.

Discussion

The event at Quad Cities Station, Unit 1 involved LLRT testing of two-ply steel expansion bellows used on piping penetrations. It was discovered by the licensee that it is not possible to perform a valid Type B LLRT on this type of bellows assembly. The single ply steel bellows assembly used at FNP is not similar in design or construction and is tested in accordance with 10 CFR 50, Appendix J.

The Dresden Nuclear Power Station, Unit 2 event involved LLRT testing of the Containment Purge valve flanges. It was found that the LLRT procedure did not challenge all possible leakage paths. The test procedure used at FNP challenges all applicable Containment Purge valve flanges. The mini purge valves on Unit 1 were inspected during the Unit 1 RF11. The mini purge exhaust valve (Q1P12V204) inside containment was discovered installed in the reverse direction. The mini-purge testing procedures were revised to test the 8-inch mini-purge valves inside containment in the accident direction. The results of the tests were satisfactory and comparable to the quarterly test method. Based on the results, the test method was changed to the reverse methodology for the RFO test, only. The quarterly test will not include reverse testing since the TS Bases state that the quarterly tests are not subject to the requirements of 10 CFR 50, Appendix J.

The event at Perry Nuclear Plant, Unit 1 involved the improper testing of relief valve flanges. The LLRT procedure tested the relief valve flanges in the reverse direction, which did not challenge the correct flanges. All CIVs included in the LLRT program at FNP are tested in accordance with 10 CFR 50, Appendix J which states, "The pressure shall be applied in the direction as that when the valve would be required to perform its safety related function, unless

it can be determined that the results from the tests for a pressure applied in a different direction will provide equivalent or more conservative results."

The Clinton Power Station, Unit 1 is a BWR and the event involved equipment not applicable to FNP.

3.5.3 IN 96-13, "Potential Containment Leak Paths Through Hydrogen Analyzers"

IN 96-13 was issued to alert addressees to the potential for containment leak paths through hydrogen analyzers either through a failure to test or a failure to restore the system after testing. Catawba Nuclear Station determined that leakage from an internal component in a hydrogen analyzer panel exceeded the containment bypass leakage limits specified in their TS. Tests showed that the source of the bypass leakage was a defective pump shaft seal on a sample pump located inside the hydrogen analyzer cabinet. Braidwood completed a containment ILRT and left the sensing lines inside the hydrogen monitor disconnected resulting in an unfiltered release path from containment to the auxiliary building in the event of an accident.

Discussion

FNP's post accident hydrogen analyzer system (PAHA) is similar to the system in use at Catawba in that testing is performed on the containment isolation valves only and not through the hydrogen analyzer itself. There are three significant differences, however, between the Catawba and the FNP hydrogen analyzers, which are as follows:

1. Unlike the Catawba installation, the FNP CIVs do close on a containment isolation signal and therefore isolate the PAHAs should a design basis accident occur.
2. Unlike the Catawba installation, the FNP PAHAs are located in the 139 ft electrical penetration room. This room is part of the penetration room filtration system, which is designed to maintain a negative pressure (in the room) and limit the release of radioisotopes to the environment in the event of a LOCA.
3. Significant leakage from the FNP PAHA would result in local radiation alarms and increasing vent stack radiation readings and/or alarms. Operations at FNP would then have the option to discontinue hydrogen monitoring on the affected unit by closing the CIVs if the source of leakage is PAHA.

The post accident combustible gas sample system (PAHA) CIVs at Plant Farley are pressure tested as part of the LLRT program during each RFO. The PAHA CIVs will close on a containment isolation signal even if the system is sampling the containment atmosphere at the time the isolation signal is received. Therefore, although functional test and calibration activities may be in progress, they will not prevent the primary containment isolation from occurring. As part of the IN response, FNP created a procedure to perform a qualitative assessment of potential radioactive leakage outside containment from the PAHA and Post Accident Containment Vent Piping.

The operability of each post accident combustible gas sample system (PAHA) is verified by a quarterly surveillance program, to satisfy TS. A yearly P.M. is performed on each PAHA. These include a pressure test of the PAHA's entries, exits and internals to completely verify the leak integrity of the tubing and components. In addition, whenever maintenance activities breach any of the PAHA's pressure boundaries, the WO planning sequence requires a pressure test. This effectively leak checks the primary components of the PAHA, which are located outboard of the CIVs and are not leak tested by the LLRT Test Program.

A review of the systems similar to the post accident combustible gas sampling system (PAHAs) was made and is contained in the discussion. The conclusions are as follows:

- The H2 recombiner and the post LOCA air mixing systems are both located inside containment and therefore no further actions are required.
- The post accident sampling system (PASS) has been discussed. Supplemental (visual) procedures are in existence to perform a quantitative assessment of potentially radioactive leakage during each outage. By procedure, a continuous sample flow is routed through the PASS. This sample flow would quickly expose most forms of leakage. In addition, a procedure is performed every 6 months and includes a pressure verification of the system at 10 psig and a vacuum verification of the system at approximately 25 inches of vacuum.
- The containment atmosphere sample systems (RE-11 / RE-12 & RE-67) have been discussed. A unit specific procedure pressurizes the RE-67 system to approximately 6 psig, performs a visual evaluation of the systems and/or system components while pressurized, and performs a leak rate measurement. This pressure test does not include the RE-11 / RE-12 elements or inboard/outboard pumps.
- The RE-11 / RE-12 portion of the containment atmospheric sample system is not required during accident conditions.
- The post accident containment venting system has been discussed. As part of the IN response, FNP created a procedure to perform a qualitative assessment of potential radioactive leakage outside containment from the PAHA and Post Accident Containment Vent Piping.

The maintenance planning work sequences for 1) the post accident combustible pump sample system (PAHA), 2) the post accident sampling system (PASS) 3) the containment atmospheric sample systems, and 4) the post accident containment venting system specifies certain instructions for reassembly. This maintenance planning work sequence modification specifies that whenever any of these system's pressure boundaries are "breached," a pressure test of the system and adjacent piping/ tubing must be performed. This pressure test will verify the reassembled integrity of the components, fittings, piping/tubing for appropriate portions of the systems which had been breached.

FNP's containment integrated leak rate test is similar to the Braidwood Station, in that, the containment penetration hydrogen sensing lines for one train are disconnected at the "sample bomb". Unlike the Braidwood Station, however, the FNP connections are self sealing quick disconnect fittings, and if they were left disconnected (as in the case of Braidwood) there would not be a leakage path. The ILRT procedure provides restoration steps and verification steps to ensure that the "sample bomb" has been replaced/restored to the proper configuration. In addition, FNP administrative procedures provide detailed guidance and controls for releasing work and functionally accepting work to insure all equipment is properly returned to service after testing or maintenance.

3.5.4 IN 99-10, "Degradation of Pre-stressing Tendon Systems in Pre-stressed Concrete Containments"

The NRC issued IN 99-10 to alert nuclear power plants to degradation of pre-stressing systems components of pre-stressed concrete containments (PCCs). The specific items addressed are

(1) pre-stressing tendon wire breakage, (2) the effects of high temperature on the pre-stressing forces in tendons, and (3) trend analysis of pre-stressing forces.

Discussion

FNP has not seen any indication of wire breakage or any of the effects from high temperature around tendons that are discussed in IN 99-10. The current FNP procedures cover all the areas discussed as probable causes for wire breakage. High temperature around tendons has not caused any low pre-stress forces during testing at FNP. In addition, the Maintenance Rule Structural Monitoring Program looks for areas of degradation to the containment pre-stressing system. Actual lift-off forces have not been used for trending of tendon forces, although FNP shows no trend of going below the minimum required pre-stress.

Based on the NRC's recommendation, recommendations were made to verify that each tendon surveillance report include trend data using actual lift-off forces in the future. Accordingly, paragraph 9 of procedures FNP-1 / 2-STP-609.0 was modified to require that future final reports include trend data using actual lift-off data.

Revision 1 to IN 99-10 corrects the observations made by the NRC staff concerning the 6th tendon surveillance performed at Oconee Unit 3 in the summer of 1995 and provides other editorial and clarifying changes.

In the original IN, it was reported that Oconee Unit 3 had experienced tendon lift-off forces, which fell below the acceptable range. The cause of the reduced lift-off forces was concluded to be tendon wire breakage. Revision 1 revises this conclusion as it states that the cause of the unacceptable lift-off forces was that Oconee had used the same tendon selection each time the lift-off forces were measured. This practice subjected those tendons to additional cyclic loadings causing a weakening of the wires. Part of the corrective action for Oconee was to commit to a random tendon selection process for future surveillances. FNP has always employed a random selection process for tendon surveillance.

Revision 1 to IN 99-10 did not change any of the conclusions or recommendations that were made as a result of the review of the original IN, as delineated in the above discussion.

3.5.5 IN 2004-09, "Corrosion of Steel Containment and Containment Liner"

The NRC issued IN 2004-09 to alert addressees to recent occurrences of corrosion in freestanding metallic containments and in liner plates of reinforced and pre-stressed concrete containments. Any corrosion (metal thinning) of the liner plate or freestanding metallic containment could change the failure threshold of the containment under a challenging environmental or accident condition. Thinning changes the geometry of the containment shell or liner plate, which may reduce the design margin of safety against postulated accident and environmental loads. Recent experience has shown that the integrity of the moisture barrier seal at the floor-to-liner or floor-to containment junction is important in avoiding conditions favorable to corrosion and thinning of the containment liner plate material. Inspections of containment at the floor level, as well as at higher elevations, have identified various degrees of corrosion and containment plate thinning.

Discussion

The FNP Containment Inspection Plan requires the inspection of the liner plate and moisture barrier seal on regular intervals. This procedure is written to comply with the examination

requirements of 10 CFR 50.55a as detailed in ASME Code Section XI, Subsections IWE and IWL or the 1992 Edition with 1992 Addenda.

The inspections of the moisture barrier seal and the liner plate have been carried out on the required scheduled intervals by registered professional civil engineers certified to IWE/IWL inspection requirements. Reports for inspection have been prepared and issued to document the inspection results. To date, no inspections have identified any adverse corrosion of the liner or excessive deterioration of the moisture barrier seal. Some areas of the moisture barrier seal have been noted for future repair to prevent any corrosion from initiating. To further enhance the inspection results, UT measurements of the liner have been performed at any suspect areas of the liner plate.

All thickness measurements taken to date show that the liner plate has deteriorated and the thickness is at or above the required design thickness.

FNP considers the current procedures with the use of certified registered professional engineers to perform the inspections adequate to meet the required inspections and detect any potential adverse corrosion problems of the liner or deterioration of the moisture barrier seal.

3.5.6 IN 2010-12, "Containment Liner Corrosion"

IN 2010-12 was issued to alert plant operators to three events that occurred where the steel liner of the containment building was corroded and degraded. At the Beaver Valley and Brunswick plants, material had been found in the concrete, which trapped moisture against the liner plant and corroded the steel. In one case, it was material intentionally placed in the building and in the other case it was foreign material, which had inadvertently been left in the form when the wall was poured. But the result in both cases was that the material trapped moisture against the steel liner plate leading to corrosion. In the third case, Salem, an insulating material placed between the concrete floor and the steel liner plate adsorbed moisture and led to corrosion of the liner plate.

Discussion:

FNP Units 1 and 2 have a containment structure as described in the IN. The containment is a concrete structure with a steel liner.

The FNP liner requires inspection for corrosion and there could be legacy items imbedded from construction or inside containment that could rub against and degrade the surface of the containment. These effects could be determined through current testing. FNP IWE/IWL inspections are scheduled per repetitive tasks at the ASME code required frequency. Inspections include random UT measurements to test for liner thinning as well as visuals for corrosion.

3.5.7 NRC Information Notice 2014-07, "Degradation of Leak-Chase Channel Systems for Floor Welds of Metal Containment Shell and Concrete Containment Metallic Liner"

The NRC issued IN 2014-07 to inform the industry 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. Specifically, this IN provides examples of operating experience at some plants of water

accumulation and corrosion degradation in the leak-chase channel system that has the potential to affect the leak-tight integrity of the containment shell or liner plate. In each of the examples, the plant had no provisions in its ISI plan to inspect any portion of the leak-chase channel system for evidence of moisture intrusion and degradation of the containment metallic shell or liner within it. Therefore, these cases involved the failure to perform required visual examinations of the containment shell or liner plate leak-chase systems in accordance with the ASME Code, Section XI, Subsection IWE, as required by 10 CFR 50.55a(g)(4).

Discussion:

The issue identified in the IN concerns the degradation or potential degradation of the inaccessible portions of the containment liner by moisture intrusion through the floor mounted LCTCs. This issue was identified at FNP during the 1R24 RFO; at that time walk downs and inspections were conducted to determine the extent of condition for all the LCTCs. As indicated in the IN, some issues were found but they were evaluated to be acceptable. The following Unit 2 outage, 2R22, walk downs and inspections were performed to determine the extent of condition and no issues were identified during those inspections. It is important to mention through that those examinations did not remove the covers and only looked for conditions in which it was believed moisture could have intruded through the floor covers.

Degradation of the containment liner due to moisture intrusion in this case would be a long-term degradation mechanism and not something that would be expected to occur over one operating cycle. With that in mind, the last Appendix J ILRT conducted on both units was Spring 2009 for Unit 1 and Fall 2008 for Unit 2, which verified the integrity/leak-tightness of containment. It is not expected that compromise of the leak-tightness of containment has occurred since the previous ILRTs due to moisture intrusion, since the degradation that would be expected is long term.

Due to this issue being identified during 1R24 at FNP, corrective actions have occurred such as inspections of the covers, but no covers were removed on either unit since initial inspection. The only two covers found missing in 1R24 were the LCTCs examined without the covers installed.

Beginning with the 2R23 and 1R26 outages, FNP included the LCTCs as part of the IWE scope. Prior to the spring of 2012, FNP did not have these items scoped under the IWE Program or the Containment Inspection Program; essentially, these items were not recognized as a potential location for moisture intrusion to the inaccessible portions of the liner plate. Following the 1R24 outage in the spring of 2012, the LCTCs were added to the Containment Inspection Plan as an Augmented Examination for both units. Subsequent to the issuance of IN 2014-07 in May 2014, FNP added the LCTCs to the IWE Program as moisture barriers.

3.5.8 RIS 2016-07, "Containment Shell or Liner Moisture Barrier Inspection"

The NRC staff identified several instances in which containment shell or liner moisture barrier materials were not properly inspected in accordance with ASME Code Section XI, Table IWE-2500-1, Item E1.30. 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."

Discussion

The Section XI Rules and Code were reviewed against the Farley and Southern Nuclear procedures. Changes were made to inspect the Liner Moisture Barrier to the standards and requirements as identified in RIS 2016-07. Upcoming current and future inspections meet this standard.

3.5.9 Operating Experience Report OE32389, "Containment Liner Through-Wall Degradation at Turkey Point-3," dated November 24, 2010

This OE describes an area in the reactor cavity pit room of Turkey Point 3 with through-wall degradation. OE was issued to inform other plants of the lessons learned from the event investigation. Lesson learned were that occasional flooding with borated water led to corrosion, and that the original coating systems used in the area was not designed for immersion. This area was not identified as a containment leak barrier until 2005 and was thought to be inaccessible due to high radiation and access difficulties.

Discussion

During review of the OE, FNP determined that formal VT-3 and General Visual examinations in accordance with ASME Section XI Table IWE-2500 had not been performed or documented for a portion of the reactor cavity area. FNP documented the lack of a previous examination in the plant's Corrective Action Program. The investigation recommended examinations be performed during the FNP-1 1R24 RFO and FNP-2 2R21 RFO. Additionally, recommendations were made to enhance the program procedures to properly document the inspection.

VT-2 examinations of the reactor vessel sump area are conducted each RFO as part of the Class 1 leakage test. It was thought that liner plate inspections in this area were conducted at the same time. It was verified that examinations in accordance with ASME Section XI Subsection IWE were not performed. No evidence of degradation of the cavity liner was identified during the VT-2 visual examinations or ILRTs during previous outages.

During the 1R24 RFO, a general visual examination was performed on the cavity liner of the reactor pressure vessel sump. Conditions of paint blistering, peeling, chipping and discoloration were noted. Engineering evaluations determined the cause of the indications were inadequate application of the top coat in the blistered area. Other damage noted appeared to be due to contact from personnel or equipment traversing the area. Recommendations were made to remove the loose paint and scale on the reactor cavity sump line to allow for follow-up UT thickness and VT-1 visual examination.

A WO was executed for painters to remove the loose paint and scale on the reactor cavity sump liner for follow-up UT thickness and VT-1 visual examinations. The completed work included removing blistered coatings and cleaning corrosion. The Coatings Program Owner performed a visual inspection and NDE personnel performed the VT-1 visual examination along with the UT thickness examination. All results were satisfactory.

Corrective Actions initiated to prevent recurrence from this event including application of approved coatings only in the area of the vertical shaft that allows access to the Reactor Cavity. Additionally, approved coatings were applied during the FNP-1 1R25 RFO in the areas which were removed during 1R24.

During the 2R21 RFO, a general visual examination was performed on the cavity liner of the reactor pressure vessel sump. Conditions of spalling, minor cracking and surface staining were noted. Review of the general visual datasheet and photos from the inspection determined no degradation of the liner plate; however, recommendations were made to include the deficient coatings in the Unqualified/Degraded Coatings Log. Coating repairs were determined to be best suited for completion during 2R22. Total deficient coatings found during the general visual examination equaled 2-square ft. The addition of the 2-square did not affect the margin within the sump screen calculation.

3.5.10 Operating Experience Report OE31696, "Concrete Containment Delamination Exposed during Steam Generator Replacement (SGR) Hydro-Excavation at Crystal River 3," August 24, 2010

This OE describes an issue during the Crystal River 3 steam generator replacement outage when a temporary opening was created to permit entry for the replacement steam generators. As part of the FNP SGR project, a series of horizontal and vertical tendons were de-tensioned in bay 34. For the particular tendon de-tensioning sequence selected for CR3 SGR opening, tensile stress is created at the interface between tensioned and de-tensioned tendons and increases with the number of de-tensioned tendons involved. At the number of de-tensioned horizontal tendons increased the tensile stress was amplified until it exceeded the tensile capacity of the concrete and cracking developed between the horizontal tendons. Continued de-tensioning and concrete removal exacerbated the cracking so severely that the cracks began to propagate spontaneously, growing together to form a delaminated sheet.

The evaluation also pointed out that four factors were required for the delamination to occur. All four are necessary and none of the contributing factors is sufficient to cause delamination. The factors are:

- Lack of radial enforcement (no radial)
- High stress peaks due to large tendons and wall design
- Certain material characteristics (material)
- Large tensile stresses – typically associated with the interface between several tensioned tendons and several de-tensioned tendons (typically during steam generator replacement) (De-tensioning)

A comparison was made between Crystal River-3 and other plants and only Crystal River had all four factors.

FNP has a pre-stressed, post tensioned concrete PWR containment with steam generators. The steam generator replacement at FNP was performed without cutting open the concrete, the steam generators were brought into containment through the containment equipment hatches. The FNP containment has reinforcing steel on both faces (minimum #18 @18 in. C/C) and radial reinforcement (#8 @12 in. C/C). Other factors include the good quality concrete used and no de-tensioning of tendons was involved.

3.6 Primary Containment Operating Experience Since Completion of Last ILRT in 2009 (FNP-1 1R22) and 2010 (FNP-2 2R20)

Root Cause Investigation for FNP Unit 1 Containment Tendon Failure:

On May 3, 2012, the FNP control room received reports of a loud noise within the radiation area of FNP-1. System operators found a tendon cable ejected from the tendon conduit into the stairwell near the FNP Unit 1 121 ft elevation batching area. Hoop tendon H7AB's field end anchor head had failed resulting in the shop end propelling the grease cover can approximately 12 ft of tendon, shims and the shop anchor head into the stairwell.

The failed hoop tendon field anchor head (H7AB) is part of the post-tensioning system for the FNP-1 reactor containment building. The post-tensioning system consists of horizontal (hoop), dome and vertical tendons based on the spatial orientation around the containment building. A total of one-hundred thirty-five (135) hoop tendons are anchored at three vertical buttresses. Three groups of dome tendons, for a total of ninety-three (93) tendons, are anchored at the vertical face of the dome ring girder. One-hundred thirty (130) vertical tendons are anchored at the top surface of the ring girder and at the bottom of the base slab.

The root cause of the FNP Unit 1 Hoop Tendon 7AB anchor head failure was the lack of monitoring additional tendon grease parameters beyond the current ASME Section XI IWL Code required parameters (which were strictly adhered to by FNP) in order to identify adverse conditions that could lead to anchor head failure.

Apparent Cause Investigation for the Containment Liner Moisture Barriers:

During the 2R23 RFO, FNP discovered that it was not meeting the intent of ASME Section XI, Subsection IWE, Category E-A, Item E1.30. Item E1.30 requires that 100 percent of the containment moisture barrier be examined each inspection period. The FNP Containment Inservice Inspection Plan only scoped the moisture barrier along the outer periphery of containment and did not scope in the moisture barriers that are used in the expansion joints that are located radially around the containment floor between the containment wall, bioshield wall and reactor vessel shield wall. In addition, the moisture barriers located around the bioshield wall, the steam generator platforms and RCP platforms were not included in the plan.

The justification for not originally including these locations in the Containment Inservice Inspection Program was due to an incorrect interpretation that they were not part of the containment pressure boundary. ASME Section XI requires the examination include moisture barrier materials intended to prevent intrusion of moisture against inaccessible areas of the pressure retaining metal containment shell or liner at the concrete to metal interfaces and at metal to metal interfaces which are not seal welded. Farley's containment liner is not a pressure retaining shell, but rather a leak-tight liner to prevent fission products from leaving containment. Therefore, the cause of the omission of the moisture barriers from the program is a misinterpretation of ASME Section XI.

Following the discovery that a portion of the moisture barrier had not been previously examined in accordance with ASME Section XI, Subsection IWE requirements, FNP performed an examination during the 1R26 and 2R23 RFOs to meet the Code requirements.

In addition to the degraded moisture barrier examinations, examinations of the LCTCs were being performed to address IN 2014-07, "Degradation of Leak Chase Channel Systems for Floor Welds of Metal Containment Shell and Concrete Containment Metallic Liner. IN 2014-07 documents the NRC position that the LCTCs were functioning as moisture barriers, although this was not their intended function.
2R23 Examination Results

During the examination, several areas of degraded moisture barrier were identified. Levels of degradation varied from portions of the moisture barrier missing completely, cracking of the moisture barrier and a lack of adhesion to the concrete surface. Much of the sealant was still pliable to the touch and still adhered to either side of the joint. However, at locations where the sealant was degraded, the sealant was easily pushed down or pulled away. At twelve locations of missing sealant throughout containment, standing water was found at varying depths with dirt/sludge material at the bottom. These locations were both inside and outside the bioshield wall at expansion joints in the floor and at the floor to wall expansion joint (not including the periphery of containment).

As a result of the identified degradation of the moisture barrier, the provisions of ASME Section XI, Subsection IWE were invoked to assess the condition of the inaccessible portion of the liner plate to ensure containment integrity had been maintained. UT thickness examinations at three locations on the containment liner plate showed no evidence of loss of material. An engineering evaluation was completed prior to the conclusion of the 2R23 RFO that evaluated the UT thickness data and determined the containment liner's leak-tight integrity was still intact and acceptable for at least one more operating cycle.

In addition to the moisture barrier examinations, all LCTC floor covers were removed to inspect the condition of the port. During the examination of the LCTCs, the covers for the LCTCs were removed to look at the pipe cap to pipe connection (moisture barrier). Liquid was discovered in two of the recessed portions of the LCTC. One LCTC did not have a pipe cap installed and another LCTC's pipe and pipe cap were completely corroded through. After all initial examinations were performed, the conditions were assessed. Further investigation into the LCTC resulted in the removal of the pipe cap on 51 locations of which 20 locations were noted to have varying levels of moisture in them. The remaining locations were noted as being dry. In addition, when the pipe cap on LCTC 50 was removed, liquid was observed flowing out of the pipe for a short time. A video probe was utilized to look inside the LCTC that had their pipe caps removed.

Two issues were discovered during the 2R23 RFO that were evaluated: the discovery of a degraded moisture barrier in several locations and evidence of liquid on the accessible portions of the liner plate. The following information was used as the Engineering Evaluation to show the inaccessible portions of the liner plate have maintained and will continue to maintain their specified design function.

Several factors were considered in the evaluation of the integrity of the liner plate since a qualified NDE examination of the liner plate could not be performed at all locations were the degraded moisture barrier was identified. Therefore, a combination of qualitative and quantitative data was utilized to ensure the integrity of the liner plate was maintained.

Quantitative Examination Results

Three locations of the inaccessible portion of the liner plate were examined utilizing UT thickness measurements. Two UT locations were on a portion of the liner plate located in two of the wetted expansion joints, the third location was underneath a leak chase channel at LCTC 49. All three examinations were performed and results were repeatable and acceptable. Nominal liner plate thickness is 1/4 in. and the three readings were as follows: 0.25 in., 0.25 in., and 0.26 in., respectively. The 0.26 in. reading was from LCTC 49 and the higher than nominal thickness reading could be attributed to the edge of the weld crown adjoining two seams of the

liner plate. The weld crown is not viewed as providing inflated data since the UT signal strength indicated good contact under the transducer.

Additional attempts were made at performing UT thickness measurements, but those attempts were unsuccessful due to inability to achieve adequate surface preparation in the expansion joints and LCTC 50. No other quantitative examinations could be performed. Attempts were made to perform a qualified IWE visual examination of the liner at several of the expansion joints and through the LCTCs, but those attempts were unsuccessful due to the amount of sludge and grit inside the locations. Attempts were made to remove the sludge and grit utilizing wet vacuums, small water pumps, and physical agitation. Qualified visual examinations were unsuccessful as well since there was a fine layer of silt and grit on the liner plate. Multiple attempts at removing the grit and silt were unsuccessful.

Qualitative Examination Results

During the investigation process numerous unqualified visual examinations were performed. All locations with missing expansion joint seal areas were visually inspected for evidence of liquid. In addition to looking for liquid, attempts were being made to perform a visual of the liner at the bottom of the expansion joints. As indicated above, the inability to fully remove the grit and silt in the joint resulted in the inability to perform a qualified or unqualified visual of the liner.

During examination of the LCTCs required by IWE□2500□1, Category E□A, Item E1.30 as moisture barriers, evidence of degradation to the moisture barrier was identified, which required an expanded scope of examinations. During the expanded scope of examinations, various locations were noted as having evidence of moisture inside the pipe. Nineteen locations were identified as having moisture or water present in the pipe. Visual examinations could not be performed past the inspection port pipe due to the channel inlet hole (1/4 in.) made into the channel not being large enough to permit the video probe to gain access. Two LCTCs were chosen for further examination, which involved enlarging the hole at the bottom of the pipe to gain access to the channel. A third was chosen as a location to enlarge the hole, but due to piping located directly above the connection, enlarging the hole could not be performed.

As indicated in the Quantitative Examination Results section, a successful UT thickness reading was obtained in LCTC 49 of the liner plate. Several attempts were made to perform a UT in LCTC 50, but all attempts were unsuccessful. An unqualified visual examination was performed utilizing a video probe down LCTC 49 and 50. Although an IWE qualified individual did not perform the examination, the video resolution on the inspection was of very good quality. The liner plate could not be seen though due to the layer of silt and grit in the channel, but no gross degradation of the liner was identified. Evidence of degradation to the leak chase channel itself was apparent from the unqualified visual and after reviewing the video. LCTC 49 and 50 were chosen because they were considered the worst-case scenario. LCTC 50 had water overflowing from it when the pipe cap was removed. LCTC 49 was found to be completely corroded through when the LCTC cover was removed. With these two being considered the worst-case scenario, examination and evaluation results will be correlated out to the other LCTCs that were not examined down past the channel for the condition of the liner. In other words, this evaluation will encompass the condition of the liner plate under the leak chase channels.

Due to the nature of the examinations performed on the LCTC channels during 2R23, there was no confirmation that the leak chase channels are free of water (exams were not adequate to ensure free of water). However, the evaluation assumed that water was left in the leak chase

channels and was acceptable until the next RFO (2R24). A supplemental inspection program will be required to identify leak chase connections with evidence of water, removal of liquid from those leak chase connections, and NDE (as required) to ensure that minimum liner plate wall will continue to be maintained. Locations remaining open to water intrusion at the moisture barrier will be required to be categorized as ASME Category E□C; therefore, requiring augmented examinations, as required by ASME Section XI.

Basis for Containment Integrity

Containment integrity was assumed to be maintained, despite the discovery of water in the expansion joint areas as evidenced by the results of the most recent ILRT. The ILRT verifies leak tightness by pressurizing containment to 43.8 psig and determining if the leakage rate is within acceptable limits. The acceptance criterion for the ILRT is $\leq 0.75\ L_a$. The last ILRT performed on Unit 2 was during the 2R20 RFO in April 2010.

The Calculated Leakage Rate L_{am} during the test was 0.0230 wt.%/day. The resulting calculated value is 6.5 times less the Maximum Allowable Leakage Rate, L_a and is 4.8 times less the acceptance criteria for the ILRT. The resulting calculated leakage indicates that a significant margin is left between the actual leakage and the allowable values. Acceptable results from the ILRT indicate that Unit 2 containment integrity is maintained. The basis for utilizing the most recent ILRT results to show containment integrity was maintained is that the test was performed approximately six years prior to the discovery of the water and the expected low corrosion rate in the six-year time period since the test.

Water Sampling

Samples of liquid from the five locations with missing sealant were taken in order to determine the liquid composition and to determine the liquid's origin.

For the locations where samples were taken from the expansion joint, in each instance, chemical analysis indicates the liquid was from recent RCS water. Radionuclide species indicate the liquid was not from a leak at power, but water processed during the outage. The boric acid concentrations were 1244 ppm, 1284 ppm and 769 ppm. The iron content was relatively low from samples taken from the expansion joints. This correlates to acceptable UT thickness readings taken at Expansion Joints 10 and 11.

The analysis performed on the samples from LCTC 49 and 50 indicated recent RCS activity. The iron content on LCTC 49 was expected due to the as-found condition of the LCTC underneath the cover; however, no boron was detected. No sampling for iron content or boron was performed on the liquid discovered in LCTC 50.

Analysis for chloride was performed at one expansion joint and LCTC 49. Two analysis methods were used for the expansion joint. The analyses revealed chloride content with values of 28 ppm, 15.6 ppm and 15.8 ppm.

To address any possible concerns that the liquid could be from groundwater intrusion, a review of containment design drawings was performed. The review confirmed that groundwater intrusion, which could affect the containment liner plate, is prevented by water stops embedded in the concrete pours and a waterproof membrane between the soil and concrete interface.

Design Considerations

After discovering that several of the expansion joints contained liquid and/or sludge of variety of materials, an investigation was performed to determine the source of the liquid. The investigation identified the octagonal shaped trench that surrounds the reactor vessel shield wall, which is used as a drain path during the outage, had degraded joints and corners that could potentially permit liquid to enter the expansion joints. This trench has two drain pipes that discharge to it; these drain pipes are fed from other drains located throughout containment. Further investigation was performed on the joints throughout the trench to gain a better understanding as to how the trench interacts with the expansion joint and to determine the extent or degree of damage. From this, it was observed that the trench contained expansion joints in the same location as the floor slab.

As stated previously, liquid was originally identified in numerous degraded expansion joints; however, further investigation resulted in drawing a conclusion that all the expansion joints had liquid in them. This liquid was believed to primarily originate from the trench. Reasoning that the trench was the primary origin for the majority of the liquid is discussed below.

1. Chemistry analyzed the two samples taken from an expansion joint for chloride content. During the analysis, process bubbles were noted in both samples. Chemistry personnel concluded that the sample contained a cleaning solution. A cleaning solution is used with water to control contamination throughout the outage. This cleaning water is sent to the sump via the trench from various locations throughout containment. Degraded portions of the expansion joints that intersect the trench provided the path for the liquid to leak into the expansion joint.

2. Chemistry analyzed samples for RCS activity; those results came back with the identification of short-lived isotopes, which would indicate that the liquid was not old. It is believed the liquid was drained to the trench at some point early in the outage.

3. Actions to remove the liquid found in the trench have been performed in several expansion joints with the missing sealant. Repairs to the degraded portions of the trench were performed during the outage as well. During subsequent investigations into the condition of the expansion joints that had liquid removed after the repairs to the trench were made, it was noted that the liquid had returned, though not to the extent that it was originally identified. The level of liquid in most of the expansion joints has decreased significantly. In some locations, all that remained in the trench is the sludge of debris that could not be removed by the pumps.

   Based on the amount of liquid found in the expansion joints after repairing the trench and removing the liquid, a strong correlation existed that the trench was the source for the liquid in the expansion joint.

4. Based on the observations and investigation made during the removal of liquid from the expansion joints, the rate at which liquid flowed back into the expansion joint, the height at which the liquid was identified, and the amount of water absorbing material (e.g., silt and compressible material in the expansion joint), it is believed that the trench is the primary origin for the liquid in the expansion joint. An additional observation made was that the level of liquid in the trench never got above the floor elevation. The liquid will never rise in the joints enough to get onto the top of the fill slab at the 105 ft -6 in. elevation because it should not rise above the elevation of the bottom of the trench. The

natural tendency is for water to seek its own level; meaning the water would tend to drain back into the trench rather than rising to an elevation higher than the trench.

Potential Sources of Liquid

A review of the RCS unidentified leak rate was performed to see if any action levels may have been reached through the past two cycles. For Unit 2, no instances in which the first action level was ever reached was identified; unidentified leak rate for the 7-day rolling average never got above 0.1 gallons per minute (gpm). In addition, no instances were identified in which the daily Unidentified RCS leak rate got above 0.5 gpm.

The investigation included a review to determine if the water could be coming from the refueling cavity when the cavity was flooded for fuel movement. A search of the Corrective Action Program database was performed and found no instances of potential reactor refueling water cavity leaks. In addition, Operations personnel were interviewed to determine if they had to make-up to the refueling cavity during the outage. FNP does not have a history of having to make-up to the refueling cavity. Operations had not had to add water for makeup during 2R23. The water level is set at the beginning of the RFO prior to moving fuel and does not have to be altered unless plant operations or plant functions require it.

Potential for Future Corrosion

Addressing the potential for future corrosion concerns was considered to ensure the integrity of the liner is maintained over the next cycle, at which point additional verification of the liner plate's integrity can be performed. One of the most significant potential sources for future corrosion would be due to boric acid leaks or residue. The worst-case scenario was believed to be a situation in which the leak source was not identified and leakage would be assumed to be coming from the RCS. Assumptions for this scenario are indicated below.

Leak Source: RCS
Boric Acid Concentration: 2600 parts per million (ppm)
Temperature of Liquid: 600°F or 200°F
Temperature of Liner Plate: ~ 120°F

Condition: It was assumed that the liquid would be in contact with the liner for the duration of the cycle and would exist in the expansion joints. Temperatures were assumed to be at the highest operating temperature of the RCS at power. However, if a leak occurred from the RCS with a temperature at 600°F, it would be expected to flash to steam once it left the confines of the piping. Another assumption that was made would be that a leak from a system that operates around 200°F occurred. This scenario would be of more concern since the EPRI Corrosion Guidebook indicates boric acid leaks around the boiling point of water would be of more concern. It was assumed that the temperature of the liner plate would be around 120°F. The temperature of the liner plate should be negligible since it was well below the boiling point of water.

Utilizing the above stated conditions and using EPRI Test Reference "A" from the EPRI Corrosion Guidebook, it was assumed that a corrosion rate of 0.24 in/year could be expected. EPRI Test Reference "A" was chosen since it appeared to be the closest condition to the scenario FNP had encountered. Conditions under Test Reference "A" involve a 2500 ppm boric acid concentration and a liquid temperature of 500°F.

This high of a corrosion rate was not anticipated though because from the liquid samples collected, the highest boron concentration was around 1200 ppm. In addition, it was expected that the liquid came from the trench and was not a continuous leak from a system during operation. Based on observations made during and after liquid removal from the expansion joints, the liquid levels have subsided in the expansion joints. If the liquid was coming from a system leak, it was expected that evidence of other leaks would be detected through the RCS Unidentified Leakrate Surveillance; evidence of leakage would be discovered during the initial containment inspection; or during the Boric Acid Corrosion Control Program Walkdown.

Review of NRC NUREG/CR-7153, Volume 4, "Aging of Concrete and Civil Structures (Reference 34)," was performed to determine if there were any expected corrosion rates that could be conservatively applied to ensure all potential issues were addressed. What was identified as applicable was that local attack may result due to accumulation of moisture in an area experiencing loss of coating integrity, or failure of adjoining floor liner sealant. The rate of attack may be rapid based on the aggressiveness of the environment. Corrosion data for an industrial environment showed the atmospheric corrosion rates were found to be 0.02 to 0.04 mm/year (0.0008 – 0.0016 in/year). A more aggressive environment for carbon steel was considered and showed corrosion rates of 0.056 mm/year (0.0022 in/year). The FNP condition was believed to be bounded by these two environments, as the current chemistry samples did not indicate a corrosive environment.

Should this corrosion rate occur over the next operating cycle, based on evaluation discussed later and assuming the liner has little to no degradation because of the examination evaluation, a corrosion rate of 0.0022 in/year would not degrade the liner to an unacceptable level over an operating cycle.

The other potential source for corrosion would be as a result of chlorides in contact with the liner. The low concentration of chlorides in the samples would not initiate degradation of the carbon steel liner plate.

For normal operating conditions, the RCS Leakage Program and monitoring conditions inside containment ensure that no major leakage occurs during normal plant operation.

Requirements to Maintain Specified Design Function of Liner

FNP is a concrete containment with a metallic liner, and by design the liner plate on the bottom of containment does not serve any structural purpose. In areas where the liner serves no structural function, its function is to perform as a leak tight membrane. This function was used to evaluate potential degradation.

If the liner plate thickness is measured to have reduced in thickness by greater than 10% of nominal thickness, which is the acceptance standard in IWE-3122.3, it can be shown through analysis that a minimum thickness of 1/32 in. is acceptable as long as it is leaktight. An evaluation was performed by FNP after the NRC required utilities to implement examination of the containment liner plate through the use of Subsection IWE of ASME Section XI. The evaluation was performed to support the examination of the containment liner plates. The evaluation concluded that the ¼" liner plate had no structural function since it was backed up by the concrete base slab.

In addition the FNP FSAR credits the liner plate as a leaktight membrane and serves no structural function. FSAR Section 3.1.44 states, "The ferritic material of the containment liner

plate is designed to function as a leaktight membrane only." FSAR Section 3.8.1.6.4 supports that conclusion further as it indicates the liner plate is not a pressure vessel and its function is to serve as a leaktight membrane.

Conclusion:

Based on the information and data obtained, it was evident that the inaccessible portions of the liner plate have maintained their specified design function as a leaktight membrane.

Although a qualified NDE method could not be performed on the liner plate in all locations where missing or degraded sections of the moisture barrier was identified, the body of information included in the evaluation support that the inaccessible portion of the liner plate had not experienced any appreciable loss of material that would compromise the liner plate's ability to perform its specified design function.

The following summarizes the information collected supporting the conclusion that the liner plate had maintained its ability to perform its specified design function.

- The UT measurements for three locations were taken in areas where degradation would have been anticipated and the results of those examinations indicate that no appreciable loss of liner plate thickness had occurred.

- In 2010, an ILRT was performed on the containment structure and the results of that test showed that the containment structure was performing its specified design function as well.

- Chemistry analysis indicated that the liquid in the expansion joints was from recent RCS water.

- The qualitative visual examinations performed did not show any gross degradation of the liner plate under the leak chase channels, which would have been expected.

- Rate of corrosion for one outage is minimal (0.0022 in/year).

- Design analysis supports a minimal thickness of 1/32 in. for the liner plate under the fill slab. Observations performed during the investigation process, and during and after the repair to the trench, support the conclusion that the liquid seen occurs during the RFO, which aids to the expectation that minimal if any corrosion would occur during the operating cycle.

- Examination results indicate that no appreciable corrosion has occurred since the last ILRT in 2010, so there is no reason to expect the liner plate has degraded to a point in which it can no longer perform its intended design function since the 2010 ILRT.

In summary, based on the examinations, chemistry analysis, design, and the corrosion assessment, reasonable assurance exists to conclude that the liner had maintained the ability to perform its specified design function and that the liner plate is capable of performing its specified design function for the next operating cycle.

Future 2R25 Examination Activities

The Farley Inservice Inspection Engineer will be performing leak-chase channel examinations consistent with the requirements of NRC Information Notice 2014-07 during the 2R25 refueling outage in Fall 2017.

1R26 Examination Results

During the examination, several areas of degraded moisture barrier were identified. Levels of degradation varied from portions of the moisture barrier missing completely, cracking of the moisture barrier, and lack of adhesion to the concrete surface. In the areas with the missing sealant, the ½" compressible material below the sealant was still in place. Much of the sealant was still pliable to touch and still adhered to either side of the joint, but at the locations of degraded sealant, it was easily pushed down or pulled away. At four locations of missing sealant throughout containment, standing water was found at varying depths with dirt/sludge material at the bottom with two having depth to obtain chemistry samples. These locations were both inside and outside the bioshield wall at expansion joints in the floor and at the floor-to-wall expansion joint (not including the periphery of containment).

As a result of the identified degradation of the moisture barrier, an investigation to the condition of the inaccessible portion of the liner plate was performed in accordance with ASME Section XI, Subsection IWE to ensure the integrity of the liner plate had been maintained. Although the 2001 Edition through 2003 Addenda of ASME Section XI does not specifically mention the requirement to evaluate the liner plate due to moisture barrier degradation, it is a standard industry practice to evaluate the condition of the inaccessible portion of the liner when a condition, such as the one identified, occurs. 10 CFR 50.55a(b)(2)(ix)(A) states, "the licensee shall evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of or result in degradation to such inaccessible areas." Furthermore, in the 2013 Edition of ASME Section XI, wording was added under paragraph IWE-3512 that supports performing an investigation to ensure the integrity of the inaccessible liner.

Quantitative Examination Results

Because several sections of the moisture barrier were degraded, limiting access to the liner, the method used to support the evaluation was to sample accessible areas to evaluate the overall integrity of the liner plate beneath the fill slab on the 104 ft -0 in. elevation. Ultrasonic thickness readings were taken on a portion of the liner plate located in one of the wetted expansion joints. Nominal liner plate thickness for this area is ¼". Readings taken during the UT thickness examination measured 0.25 in.

Additional attempts were made at performing UT thickness measurements, but those attempts were unsuccessful due to the inability to achieve adequate surface preparation in the expansion joints. Attempts were also made to perform a qualified IWE visual examination of the liner at several of the expansion joints, but those attempts were unsuccessful due to the amount of sludge and grit inside the locations. Attempts were made to remove the sludge and grit using vacuums and physical agitation. All attempts at removing the liquid, grit and silt were unsuccessful, resulting in an unsuccessful performance of a qualified visual examination.

Qualitative Examination Results

During the investigation process, numerous visual inspections were performed. All locations with missing expansion joint seal areas were visually inspected for evidence of liquid. In addition to looking for liquid, an attempt was made to perform a visual examination of the liner at the bottom of the expansion joints. As indicated above, the inability to fully remove the liquid, grit, and silt in the joint resulted in the inability to perform a qualified or unqualified visual inspection of the liner.

Basis for Containment Integrity

Maintenance of containment integrity was assumed, despite the discovery of water in the expansion joint areas as evidenced by the results of the most recent ILRT. The ILRT verifies leak tightness by pressurizing containment to 43.8 psig and determining if the leakage rate is within acceptable limits. The acceptance criterion for the ILRT is ≤ 0.75 L_a. The last ILRT performed on Unit 1 was during the 1R22 RFO in April 2009.

The Calculated Leakage Rate L_{am} during the test was 0.0473 wt.%/day. The resulting calculated value is 3 times less the Maximum Allowable Leakage Rate, L_a and is 2.4 times less the acceptance criteria for the ILRT. The resulting calculated leakage indicates that a significant margin is left between the actual leakage and the allowable values. Acceptable results from the ILRT indicate that Unit 1 containment integrity is maintained. The basis for utilizing the most recent ILRT results to show containment integrity was maintained is that the test was performed approximately six years prior to the discovery of the water and the expected low corrosion rate in the six-year time period since the test.

Water Sampling

An attempt at sampling water from many locations was performed; however, only five had substantial amounts of water. The locations sampled included expansion joints 6 and 10 along with LCTCs 4, 27 and 33. Sample results in expansion joints 6 and 10 resulted in analyses that appear to be RCS water that is older than one fuel cycle. Both locations' samples had high amounts of radioactivity, but lacked short-lived isotopes. LCTC 33 also came back without any short-lived isotopes. LCTC came back without any radionuclides. LCTC 4 had water on the top of its cover, in the port, and on the liner. Samples from in the port and on the liner were taken. These were the only two locations that had a sufficient sample to perform full chemistry analyses. In both samples, the longest living isotopes are Cesium-137 and Europium-152. These isotopes have half-lives of 30.06 years and 13.55 years, respectively. The water found outside of the leak chase test channel pipe had much higher levels of both isotopes as well as 10 times the total activity. It was believed that the water on the outside of the pipe cap was from a recent RCS spill during draining while the internal water was mostly older. The results indicate that the majority of the water found in the channel was older and the installed pipe cap served some function as a moisture barrier.

The sample taken from the liner on LCTC 4 was sampled for iron, chlorides, boron and pH. The iron analysis came out to .204 parts per million (ppm). The value was considered to be relatively low and indicated a lost rate of past corrosion. The chloride content results were 63.5 ppm, boron at 173 ppm and pH at 9.01. These results indicate an environment with low corrosion rates despite the addition of the more recent RCS water.

To address any possible concerns that the liquid could have originated as groundwater intrusion, a review of containment design drawings was performed. The review confirmed that groundwater intrusion, which could affect the containment liner plate, is prevented by water

stops embedded in the concrete pours and a waterproof membrane between the soil and concrete interface.

Design Considerations

After discovering that several of the expansion joints contained liquid and/or sludge comprised of a variety of materials in 2R23, an investigation was performed to determine the source of the liquid. The results of the investigation showed the octagonal shaped trench that surrounds the reactor vessel shield wall, which is used as a drain path during the outage, had degraded joints and corners that could potentially permit liquid to enter the expansion joints. This trench has two drainpipes that discharge to it, which are fed from other drains located throughout containment. During the review it was observed that the trench contains expansion in the same location as the floor slab.

As stated previously, liquid was originally identified in numerous degraded expansion joints during 2R23; further investigation resulted in drawing a conclusion that all expansion joints contained some liquid. It is believed that this liquid primarily originated from the trench. Based on the findings during 2R23, it was decided to reseal any portions of the Unit 1 trench during 1R26 that showed degradation to prevent exacerbation of the issue. Additional conclusions showing the trench was the primary origin for the majority of the liquid are provided below:

1. During 2R23, chemistry analyzed the two samples taken from two expansion joints for chloride content. During analysis process bubbles were noted in both samples. Chemistry personnel concluded that the sample contained cleaning solution. A cleaning solution is used with water to control contamination throughout the outage. This cleaning water is sent to the sump via the trench from various locations throughout containment. Degraded portions of the expansion joints that intersect the trench provided the path for the liquid to leak into the expansion joint. There was an insufficient amount of water at the investigated liner during 1R26 to repeat the same sampling and evaluation. The lack of water volume is believed to be due to resealing the trough prior to draining to it.

2. The water samples were analyzed for RCS Activity. During 2R23, those results came back with the identification of short-lived isotopes, which would indicate that the liquid was not old. It is believed the liquid was drained to the trench at some point early in the outage. For 1R26, no isotopes with half-lives shorter than 1000 days were found. It was concluded that no new RCS water was found during 1R26.

3. During 2R23, actions to remove the liquid found in the trench were performed in several expansion joints with the missing sealant. Repairs to the degraded portions of the trench were performed during that outage as well. During subsequent investigations into the condition of the expansion joints that had liquid removed after repairs to the trench were made, it was noted that the liquid had returned, but not to the extent it was originally identified. The level of liquid in most of the expansion joints decreased significantly. In some locations, all that was left of the sludge of debris that could not be removed by the pumps. Based on the amount of liquid found in the Unit 2 expansion joints after repairing the trench is the source for the liquid in the expansion joints.

4. Based on observations and investigation made during removal of the liquid from the expansion joints during 2R23, the rate at which liquid flowed back into the expansion joint, the height at which the liquid was identified, and the amount of water absorbing

material, e.g., silt and compressible material in the expansion joint, it is believed that the trench is the primary origin for the liquid in the expansion joints. An additional observation made is that the level of liquid in the trench never got above the floor elevation. The liquid will never rise in the joints enough to get onto the top of the fill slab at the 105 ft -6 in. elevation because it should not rise above the elevation of the bottom of the trench. The natural tendency is for water to seek its own level; meaning the water would tend to drain back into the trench rather than rising to an elevation higher than the trench.

Potential Sources of Liquid

A review of cycle operating experience was performed to ensure all potential sources of liquid were considered that could have contributed to the liquid in the expansion joints and leak chases. The three locations that resulted in enough of a sample to evaluate were 4, 27 and 33.

Samples taken from the expansion joints came back with results indicating it was RCS water, older than one cycle; therefore, no leak was thought to be actively draining to the expansion joints. The water found can most likely be linked to water coming from the unsealed expansion joints in the trough during RFO draining. Since this is considered the primary source of water in these locations, it was assumed that the most water was drained there early in an RFO. Boron concentrations are low at the end of a cycle; therefore, the corrosivity of the water that would have been present would be low. Since the expansion joints in the trough have been repaired, this source of liquid will be eradicated. This is an item that should be walked down early each outage to ensure integrity.

Two component cooling water (CCW) leakages were identified during the latest refueling cycle. The lack of nuclides in the sample discovered in LCTC 27 indicates that the moisture of locations near this could be a result from the pair of leaks. FNP keeps chromates in their CCW; therefore, this moisture would not increase corrosion of the liner in these areas.

Leak chase 4 had standing water on top of it with very short-lived isotopes. It had a strong presence from Krypton-90 and Europium-152M which have half-lives of 32.2 seconds and 9.31 seconds, respectively. This is indicative of new RCS water. Given that this leak chase is a low point, it is believed that some RCS water was spilt during draining to the trough and settled at this location. Water that gathers in leak chases in this manner would have low boric acid concentrations (173 ppm inside LCTC 4). The potential for future corrosion is addressed in the next section and for situations like these it is expected to be around 0.0008 to 0.0016 inches per year based on the boron concentrations expected.

The final leak chase with enough water to perform a gamma spectroscopy was number 33. This location only reported Cobalt-60. Cobalt-60 has a half-life of 5.27 years and decays to the stable Nickel-60. Being that this is the only nuclide that was found, it could be determined that this is old RCS water. The vast majority of corrosion that would have occurred would have occurred prior to the most recent ILRT.

A review of RCS unidentified leak rate was performed to see if any action levels may have been reached through the past two cycles. For Unit 1, no instance in which the first action level was ever reached was identified; unidentified leak rate for the 7-day rolling average never got above 0.04 gallons per minute (gpm). In addition, no instances were identified in which the daily unidentified RCS leak rate got above 0.14 gpm.

Potential for Future Corrosion

Addressing the potential for future corrosion concerns was considered to ensure the integrity of the liner is maintained over the next cycle, at which point additional verification of the liner plate's integrity has been maintained can be performed. One of the most significant potential sources for future corrosion would be due to boric acid leaks or residue. The worst-case scenario is believed to be a situation in which the leak source was not identified and leakage would be assumed to be coming from the RCS. Assumptions for this scenario are indicated below.

Leak Source: RCS
Boric Acid Concentration: 2600 ppm
Temperature of Liquid: 600 F or 200°F
Temperature of Liner Plate: Approximately 120°F

Condition: It is assumed that the liquid will be in contact with the liner for the duration of the cycle and would exist in the expansion joints. Temperatures are assumed to be at the highest operating temperature of RCS at power. However, if a leak occurs from the RCS with a temperature at 600°F it would be expected to flash to steam once it left the confines of the piping. Another assumption that could be made would be that a leak from a system that operates around 200°F occurs. This scenario could be of more concern since the EPRI Corrosion Guidebook indicates boric acid leaks around the boiling point of water would be of more concern. It is assumed that the temperature of the liner plate would be around 120°F. The temperature of the liner plate should be negligible since it is well below the boiling point of water.

Utilizing the above conditions and using EPRI Test Reference "A" from the EPRI Corrosion Guidebook, it is assumed that a corrosion rate of 0.24 in/year can be expected. EPRI Test Reference "A" was chosen since it appears to be the closest condition to the scenario FNP has encountered. Conditions under Test Reference "A" involve a boric acid concentration of 2500 ppm and a liquid temperature of 500°F.

This high of a corrosion rate is not expected to be seen because of the low boron concentrations found from sampling, the highest being 173 ppm. The highest boron concentration observed during 2R23 was around 1200 ppm. It is reasonable to assume that liquid that could come in contact with the FNP-1 containment liner could have a boron concentration of 1200 ppm based on the results from 2R23. Nonetheless, the conclusions drawn on the integrity of the liner plate due to potential for corrosion would still remain valid. In addition, it is expected that the liquid comes from the trench and is not a continuous leak from a system during operation. Based on the observations made during 2R23 during and after liquid removal from the expansion joints, liquid levels have subsided in the expansion joints. If the liquid was coming from a system leak, it would be expected that evidence of other leaks would be detected through the RCS Unidentified Leakrate Surveillance or evidence of leakage would be discovered during the initial containment inspection or during the Boric Acid Corrosion Control Program Walkdown.

A review of NRC NUREG/CR-7153, Volume 4, "Aging of Concrete and Civil Structures" (Reference 34) was performed to determine if there were any expected corrosion rates that could be conservatively applied to ensure all potential issues were addressed. What was identified as applicable is that local attack may result due to accumulation of moisture in an area experiencing loss of coating integrity, or failure of adjoining floor liner sealant. The rate of attack

may be rapid based on the aggressiveness of the environment. Corrosion data for an industrial environment, the atmospheric corrosion rates were found to be 0.02 to 0.04 mm/year (0.0008 to 0.0016 in/year). A more aggressive environment for carbon steel was considered and showed corrosion rates of 0.056 mm/year (0.0022 in/year). The FNP condition was believed to be bounded by these two environments, as the chemistry samples did not indicate a corrosive environment.

Should this corrosion rate occur over the next operating cycle, based on an evaluation discussed later and assuming the liner has little to no degradation because of our examination evaluation, a corrosion rate of 0.0022 in/year would not degrade the liner to an unacceptable level over the next operating cycle.

The other potential source for corrosion would be as a result of chlorides in contact with the liner. The low concentration of chlorides in the samples would not initiate degradation of the carbon steel liner plate.

For normal operating conditions, the RCS Leakage Program and monitoring conditions inside containment ensure that no major leakage occurs during normal plant operation.

Requirements to Maintain Specified Design Function of Liner

FNP is a concrete containment with a metallic liner, and by design the liner plate on the bottom of containment does not serve any structural purpose. In areas where the liner serves no structural function; its function is to perform as a leak tight membrane. This function was used to evaluate potential degradation.

If the liner plate thickness is measured to have reduced in thickness greater than 10% of nominal thickness, which is the acceptance standard in IWE-3122.3, it can be shown through analysis that a minimum thickness of 1/32 in. is acceptable as long as it is leaktight. An evaluation was performed by FNP after the NRC required utilities to implement examination of the containment liner plate through the use of Subsection IWE of ASME Section XI. The evaluation was performed to support the examination of the containment liner plates. The evaluation concluded that the ¼" liner plate had no structural function since it was backed up by the concrete base slab.

In addition the FNP FSAR credits the liner plate as a leaktight membrane and serves no structural function. FSAR Section 3.1.44 states, "The ferritic material of the containment liner plate is designed to function as a leaktight membrane only." FSAR Section 3.8.1.6.4 supports that conclusion further as it indicates the liner plate is not a pressure vessel and its function is to serve as a leaktight membrane.

Conclusion:

Based on the information and data obtained, it was evident that the inaccessible portions of the liner plate had maintained their specific design function as a leaktight membrane.

Although a qualified NDE method could not be performed on the liner plate in all locations where missing or degraded sections of the moisture barrier was identified, the body of information included in the evaluation supported the conclusion that the inaccessible portions of the liner plate had not experienced any appreciable loss of material that would compromise the liner plate's ability to perform its specified design function.

The following summarizes the information collected that support the conclusion the liner plate has maintained its ability to perform its specified design function.

- The UT thickness measurements for the three locations were taken in areas where degradation would be anticipated and the results of those examinations indicate that no appreciable loss of liner plate thickness has occurred.

- In 2009, an ILRT was performed on the containment structure and the results of that test showed that the containment structure was performing its specified design function as well.

- The qualitative visual inspections performed did not show any significant degradation of the liner plate directly below the test connections, which would have expected to be observed.

- Rate of corrosion for one outage is minimal (0.0022 in./year).

- Design analysis supports a minimal thickness of 1/32 in. for the liner plate under the fill slab.

- Observations performed during the investigation process and during and after the repair to the trench support the conclusion that the liquid seen occurs during the RFO, which aids to the expectation that minimal, if any corrosion would occur during the operation cycle.

- Examination results indicate that no appreciable corrosion has occurred since the last ILRT in 2009, so there is no reason to expect the liner plate has degraded to a point in which it can no longer perform its intended design function since the 2009 ILRT.

In summary, based on the examinations, chemistry analysis, design and the corrosion assessment, reasonable assurance exists to conclude that the liner has maintained the ability to perform its specified design function and that the liner plate is capable of performing its specified design function for the next operating cycle.

Future 1R27 Examination Activities

The Farley Inservice Inspection Engineer will be performing leak-chase channel examinations consistent with the requirements of NRC Information Notice 2014-07 during the 1R27 refueling outage in Fall 2016.

3.7 License Renewal Aging Management

Renewed operating licenses for FNP Units 1 and 2 were issued on May 12, 2005, under NUREG-1825, "Safety Evaluation Report Related to the License Renewal of the Joseph M. Farley Nuclear Plant, Units 1 and 2," (ML050630571) (Reference 32), extending the original licensed operating term by 20 years. FNP Units 1 and 2 will enter the period of extended operation on June 26, 2017, and April 1, 2021, for Units 1 and 2, respectively. The following

programs, which are part of the supporting basis of this LAR, are also Aging Management Programs at FNP.

3.7.1 Aging Management Programs

Inservice Inspection (ISI) Program

The Inservice Inspection Program will be implemented during the period of extended operation in accordance with 10 CFR 50.55a, which imposes the inservice inspection requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI, for Class 1, 2, and 3 (Subsections IWB/IWC/IWD) pressure-retaining components and their integral attachments, containment and integral attachments (Subsections IWE/IWL), and the applicable component supports (Subsection IWF). In addition, FNP Classes 1 and 2 piping weld examinations will be performed per an NRC staff-approved risk-informed ISI program (Examination Categories B-F, B-J, C-F-1 and C-F-2).

The continued implementation of applicable 10 CFR 50.55a requirements, with approved alternatives and relief requests, will provide reasonable assurance that the aging effects will be managed such that the systems and components within the scope of the program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

This program is consistent with 10 attributes of the collection of acceptable programs described in NUREG-1801, Sections XI.M1, XI.M12, XI.S1, XI.S2, XI.S3 and XI.S4 with the clarification that exceptions to ASME Code requirements granted by approved alternatives or relief requests are not considered to be exceptions to the NUREG-1801 aging management program criteria.

Appendix J

FNP uses the 10 CFR 50, Appendix J, Option B program to monitor the leakage through primary containment. The Appendix J program scope will include all leakage paths including containment welds, valves fittings and components that penetrate containment. The leakage-limiting boundaries for these containment penetrations are also monitored.

The Appendix J Program along with the ASME Section XI, IWE and IWL programs are used to detect initiation of aging degradation of containment. Methods used to detect aging effects of containment will be implemented consistent with GALL Section XI.S1, S2 and S4 in that the methods used will be aimed at detecting aging and enhanced leakage detection methods are in place.

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)	**FNP Response**

Table 3.8.1-1, NEI 94-01 Revision 2-A Limitations and Conditions	
Limitation/Condition (From Section 4.0 of SE)	**FNP 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.)	FNP 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 3.4.2 of this submittal.
The licensee addresses the areas of the containment structure potentially subjected to degradation. (Refer to SE Section 3.1.3.)	Reference Sections 3.4.2, 3.5 and 3.6 of this 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 are no major modifications planned.
The normal Type A test interval should be less than 15 years. If a licensee has to 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.)	FNP 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 94-01 Revision 2-A, SER Section 3.1.1.2, FNP 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. FNP was not licensed under 10 CFR Part 52.

3.8.2 Limitations and Conditions Applicable to NEI 94-01 Revision 3-A

The NRC staff found that the guidance in NEI TR 94-01, Revision 3, was acceptable for referencing by licensees in the implementation for the optional performance-based requirements of Option B to 10 CFR Part 50, Appendix J. However, the NRC staff identified two conditions on the use of NEI TR 94-01, Revision 3 (Reference NEI 94-01 Revision 3-A, NRC SER 4.0, Limitations and Conditions):

Topical Report Condition 1

NEI TR 94-01, Revision 3, is requesting that the allowable extended interval for Type C LLRTs be increased to 75 months, with a permissible extension (for non-routine emergent conditions)

of nine months (84 months total). The staff is allowing the extended interval for Type C LLRTs be increased to 75 months with the requirement that a licensee's post-outage report include the margin between the Type B and Type C leakage rate summation and its regulatory limit. In addition, a corrective action plan shall be developed to restore the margin to an acceptable level. The staff is also allowing the non-routine emergent extension out to 84-months as applied to Type C valves at a site, with some exceptions that must be detailed in NEI TR 94-01, Revision 3. At no time shall an extension be allowed for Type C valves that are restricted categorically (e.g., BWR MSIVs), and those valves with a history of leakage, or any valves held to either a less than maximum interval or to the base refueling cycle interval. Only non-routine emergent conditions allow an extension to 84 months.

Response to Condition 1

Condition 1 presents three (3) separate issues that are required to be addressed. They are as follows:

- ISSUE 1 – The allowance of an extended interval for Type C LLRTs of 75 months carries the requirement that a licensee's post-outage report include the margin between the Type B and Type C leakage rate summation and its regulatory limit.

- ISSUE 2 – In addition, a corrective action plan shall be developed to restore the margin to an acceptable level.

- ISSUE 3 – Use of the allowed 9-month extension for eligible Type C valves is only authorized for non-routine emergent conditions.

Response to Condition 1, Issue 1

The post-outage report shall include the margin between the Type B and Type C Minimum Pathway Leak Rate (MNPLR) summation value, as adjusted to include the estimate of applicable Type C leakage understatement, and its regulatory limit of 0.60 L_a.

Response to Condition 1, Issue 2

When the potential leakage understatement adjusted Type B and C MNPLR total is greater than the FNP leakage summation limit of 0.50 L_a, but less than the regulatory limit of 0.6 L_a, then an analysis and determination of a corrective action plan shall be prepared to restore the leakage summation margin to less than the FNP leakage limit. The corrective action plan shall focus on those components which have contributed the most to the increase in the leakage summation value and what manner of timely corrective action, as deemed appropriate, best focuses on the prevention of future component leakage performance issues so as to maintain an acceptable level of margin.

Response to Condition 1, Issue 3

FNP will apply the 9-month allowable interval extension period only to eligible Type C components and only for non-routine emergent conditions. Such occurrences will be documented in the record of tests.

Topical Report Condition 2

The basis for acceptability of extending the ILRT interval out to once per 15 years was the enhanced and robust primary containment inspection program and the local leakage rate testing of penetrations. Most of the primary containment leakage experienced has been attributed to penetration leakage and penetrations are thought to be the most likely location of most containment leakage at any time. The containment leakage condition monitoring regime involves a portion of the penetrations being tested each refueling outage, nearly all LLRTs being performed during plant outages. For the purposes of assessing and monitoring or trending overall containment leakage potential, the as-found minimum pathway leakage rates for the just tested penetrations are summed with the as-left minimum pathway leakage rates for penetrations tested during the previous 1 or 2 or even 3 refueling outages. Type C tests involve valves, which in the aggregate, will show increasing leakage potential due to normal wear and tear, some predictable and some not so predictable. Routine and appropriate maintenance may extend this increasing leakage potential. Allowing for longer intervals between LLRTs means that more leakage rate test results from farther back in time are summed with fewer just tested penetrations and that total used to assess the current containment leakage potential. This leads to the possibility that the LLRT totals calculated understate the actual leakage potential of the penetrations. Given the required margin included with the performance criterion and the considerable extra margin most plants consistently show with their testing, any understatement of the LLRT total using a 5-year test frequency is thought to be conservatively accounted for. Extending the LLRT intervals beyond 5 years to a 75-month interval should be similarly conservative provided an estimate is made of the potential understatement and its acceptability determined as part of the trending specified in NEI TR 94-01, Revision 3, Section 12.1.

When routinely scheduling any LLRT valve interval beyond 60-months and up to 75-months, the primary containment leakage rate testing program trending or monitoring must include an estimate of the amount of understatement in the Type B and C total, and must be included in a licensee's post-outage report. The report must include the reasoning and determination of the acceptability of the extension, demonstrating that the LLRT totals calculated represent the actual leakage potential of the penetrations.

Response to Condition 2

Condition 2 presents two (2) separate issues that are addressed, as follows:

- ISSUE 1 – Extending the LLRT intervals beyond 5 years to a 75-month interval should be similarly conservative provided an estimate is made of the potential understatement and its acceptability determined as part of the trending specified in NEI TR 94-01, Revision 3, Section 12.1.

- ISSUE 2 – When routinely scheduling any LLRT valve interval beyond 60 months and up to 75 months, the primary containment leakage rate testing program trending or monitoring must include an estimate of the amount of understatement in the Type B and C total, and must be included in a licensee's post-outage report. The report must include the reasoning and determination of the acceptability of the extension, demonstrating that the LLRT totals calculated represent the actual leakage potential of the penetrations.

Response to Condition 2, Issue 1

The change in going from a 60-month extended test interval for Type C tested components to a 75-month interval, as authorized under NEI 94-01, Revision 3-A, represents an increase of 25% in the LLRT periodicity. As such, FNP, Units 1 and 2 will conservatively apply a potential

leakage understatement adjustment factor of 1.25 to the actual As-Left leak rate, which will increase the As-Left leakage total for each Type C component currently on greater than a 60-month test interval up to the 75-month extended test interval. This will result in a combined conservative Type C total for all 75-month LLRTs being "carried forward" and will be included whenever the total leakage summation is required to be updated (either while on line or following an outage).

When the potential leakage understatement adjusted leak rate total for those Type C components being tested on greater than a 60-month test interval up to the 75-month extended test interval is summed with the non-adjusted total of those Type C components being tested at less than or equal to a 60-month test interval, and the total of the Type B tested components, results in the MNPLR being greater than the FNP leakage summation limit of 0.50 L_a, but less than the regulatory limit of 0.6 L_a, then an analysis and corrective action plan shall be prepared to restore the leakage summation value to less than the FNP leakage limit. The corrective action plan shall focus on those components which have contributed the most to the increase in the leakage summation value and what manner of timely corrective action, as deemed appropriate, best focuses on the prevention of future component leakage performance issues.

Response to Condition 2, Issue 2

If the potential leakage understatement adjusted leak rate MNPLR is less than the FNP leakage summation limit of 0.50 L_a, then the acceptability of the greater than a 60-month test interval up to the 75-month LLRT extension for all affected Type C components has been adequately demonstrated and the calculated local leak rate total represents the actual leakage potential of the penetrations.

In addition to Condition 1, ISSUES 1 and 2, which deal with the MNPLR Type B and C summation margin, NEI 94-01, Revision 3-A also has a margin related requirement as contained in Section 12.1, Report Requirements.

A post-outage report shall be prepared presenting results of the previous cycle's Type B and Type C tests, and Type A, Type B and Type C tests, if performed during that outage. The technical contents of the report are generally described in ANSI/ANS-56.8-2002 and shall be available on-site for NRC review. The report shall show that the applicable performance criteria are met, and serve as a record that continuing performance is acceptable. The report shall also include the combined Type B and Type C leakage summation, and the margin between the Type B and Type C leakage rate summation and its regulatory limit. Adverse trends in the Type B and Type C leakage rate summation shall be identified in the report and a corrective action plan developed to restore the margin to an acceptable level.

At FNP, in the event an adverse trend in the aforementioned potential leakage understatement adjusted Type B and C summation is identified, then an analysis and determination of a corrective action plan shall be prepared to restore the trend and associated margin to an acceptable level. The corrective action plan shall focus on those components which have contributed the most to the adverse trend in the leakage summation value and what manner of timely corrective action, as deemed appropriate, best focuses on the prevention of future component leakage performance issues.

At FNP, an adverse trend is defined as three (3) consecutive increases in the final pre-RCS Mode Change Types B and C MNPLR leakage summation values, as adjusted to include the estimate of applicable Type C leakage understatement, as expressed in terms of L_a.

3.9 Conclusion

NEI 94-01, Revision 3-A, dated July 2012, and the conditions and limitations specified in NEI 94-01, Revision 2-A, dated October 2008, describes 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 and includes provisions for extending Type A intervals to 15 years and Type C test intervals to 75 months. NEI 94-01, Revision 3-A delineates a performance-based approach for determining Type A, Type B, and Type C containment leakage rate surveillance test frequencies. FNP is adopting the guidance of NEI 94-01, Revision 3-A, and the conditions and limitations specified in NEI 94-01, Revision 2-A, for the FNP 10 CFR 50, Appendix J testing program plan.

Based on the previous ILRTs conducted at FNP, Units 1 and 2, it may be concluded that the permanent extension of the containment ILRT interval from 10 to 15 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 FNP inspection programs:

- Containment Inservice Inspection Program (IWE and IWL)
- Containment Inspections per TS SR 3.6.1.1 and SR 3.6.1.2
- Inspection of Primary Containment Coatings

This experience is supplemented by risk analysis studies, including the FNP risk analysis provided in Attachment (1). 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 since it represents only a small change in the FNP 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.

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 50, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors." 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 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 frequency will not directly result in an increase in containment leakage.

EPRI TR-1009325, Revision 2, provides 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 states that Type A ILRT intervals of up to 15 years are allowed by this guideline. The Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals, EPRI Report 1018243 (formerly TR-1009325, Revision 2) 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 staff 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 staff finds that the Type A testing methodology as described in ANSI/ANS-56.8-2002, 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 (Reference 16), 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 TSs as delineated in RG 1.177 and RG 1.174. The NRC staff, therefore, found that this guidance was acceptable for referencing by licensees proposing to amend their TS in regards to containment leakage rate testing, subject to the limitations and conditions noted in Section 4.0 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 conditions and limitations 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 leaktight. 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 regards 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 conditions and limitations 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 license amendment request is similar in nature to the following license amendments previously authorized by the NRC to extend the Type A test frequency to 15 years and the Type C test frequency to 75 months:

- Surry Power Station, Units 1 and 2 (Reference 23)
- Donald C. Cook Nuclear Plant, Units 1 and 2 (Reference 24)
- Beaver Valley Power Station, Unit Nos. 1 and 2 (Reference 25)
- Calvert Cliffs Nuclear Power Plant, Unit Nos. 1 and 2 (Reference 26)
- Peach Bottom Atomic Power Station, Units 2 and 3 (Reference 27)
- Comanche Peak Nuclear Power Plant, Units 1 and 2 (Reference 28)

4.3 No Significant Hazards Consideration

Southern Nuclear Operating Company (SNC) 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 activity involves the revision of Joseph M. Farley Nuclear Plant (FNP), Units 1 and 2, Technical Specification (TS) 5.5.17, "Primary Containment Leakage Rate Testing Program," to allow the extension of the Type A integrated leakage rate test (ILRT) containment test interval to 15 years, and the extension of the Type C local leakage rate test (LLRT) interval to 75 months. The current Type A test interval of 120 months (10 years) would be extended on a permanent basis to no longer than 15 years from the last Type A test. The current Type C test interval of 60 months for selected components would be extended on a performance basis to no longer than 75 months. Extensions of up to nine months (total maximum interval of 84 months for Type C tests) are permissible only for non-routine emergent conditions.

   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 to once-per-fifteen 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 probabilistic risk analysis (PRA) is 1.08E-02 person-rem/year for Unit 1 and 9.89 E-03 person-rem/year for Unit 2. 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 January 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 FNP 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 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 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 test interval extensions do not significantly increase the consequences of an accident previously evaluated.

The proposed amendment also deletes exceptions previously granted under TS Amendments 159 (FNP Unit 1) and 150 (FNP Unit 2) to allow one-time extensions of the ILRT test frequency for FNP. These exceptions were for activities that would have already taken place by the time this amendment is approved; therefore, their deletion is solely an administrative action that has no effect on any component and no impact on how the unit is operated.

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 TS 5.5.17, "Containment Leakage Rate Testing Program," involves the extension of the FNP Type A containment test interval to 15 years and the extension of the Type C test interval to 75 months. 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.

   The proposed amendment also deletes exceptions previously granted under TS Amendments 159 (FNP Unit 1) and 150 (FNP Unit 2) to allow one-time extensions of the ILRT test frequency for FNP. These exceptions were for activities that would have already taken place by the time this amendment is approved; therefore, their deletion is solely an administrative action that does not result in any change in how the unit is operated.

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 TS 5.5.17 involves the extension of the FNP Type A containment test interval to 15 years and the extension of the Type C test interval to 75 months for selected components. 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 Containment Leak Rate Testing Program exist to ensure that the degree of containment structural integrity and leak-tightness that is considered in the plant safety analysis is maintained. The overall containment leak rate limit specified by TS is maintained.

   The proposed change involves only the extension of the interval between Type A containment leak rate tests and Type C tests for FNP. The proposed surveillance interval extension is bounded by the 15-year ILRT interval and the 75-month Type C test interval currently authorized within NEI 94-01, Revision 3-A. Industry experience supports the conclusions that Type B and C testing detects a large percentage of containment leakage paths and that the percentage of containment leakage paths that are detected only by Type A testing is small. The containment inspections performed in accordance with ASME Section XI and Technical Specifications serve to provide a high degree of assurance that the containment would not degrade in a manner that is detectable only by Type A testing. The combination of these factors ensures that the margin of safety in the plant safety analysis 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 changes to the Type A and Type C test intervals.

   The proposed amendment also deletes an exception previously granted under TS Amendments 159 (FNP Unit 1) and 150 (FNP Unit 2) to allow one-time extensions of the ILRT test frequency for FNP. This exception was for an activity that would have already taken place by the time this amendment is approved; therefore, the deletion is solely an administrative action and does not change how the unit is operated and maintained. Thus, there is no reduction in any margin of safety.

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

Based on the above, Southern Nuclear 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 1.163, Performance-Based Containment Leak-Test Program, September 1995

2. 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. ANSI/ANS-56.8-2002, "Containment System Leakage Testing Requirements," November 2002

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

6. An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis, Regulatory Guide 1.174, May 2011

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

8. NUREG-1493, "Performance-Based Containment Leak-Test Program," July 1995

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

10. Letter from NRC (M. J. Maxin) to NEI (J.C. Butler), '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),' dated June 25, 2008 (ML081140105)

11. Letter from NRC (S. Bahadur) to NEI (B. Bradley), 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)," dated June 8, 2012

12. Letter from NRC (J. I. Zimmermann) to SNC (D. N. Morey), "Issuance of Amendments – Joseph M. Farley Nuclear Plant, Units 1 and 2 (TAC Nos. M95774 and M95775)," dated September 3, 1996

13. Letter from NRC (F. Rinaldi) to SNC (J.B. Beasley, Jr.), "Joseph M. Farley Nuclear Plant, Units 1 and 2 Re: Issuance of Amendments (TAC Nos. MB4756 and MB4757)," dated March 21, 2003

14. 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, November 2001

15. Letter from Calvert Cliffs Nuclear Power Plant (C. H. Cruse) to NRC (Document Control Desk), "Response to Request for Additional Information Concerning the License Amendment Request for a One-Time Integrated Leakage Rate Test Extension," Docket No. 50-317, dated March 27, 2002

16. Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals, Revision 2-A of 1009325, EPRI, Palo Alto, CA. 1018243, October 2008

17. Westinghouse Letter LTR-RAM-I-13-064, Revision 0-A, Transmittal of Farley Internal Events PRA Model for Units 1 and 2 – Revision 9, Version 3 (SNC Calculation PRA-BC-F-14-001, Version 1, dated January 28, 2014)

18. American Society of Mechanical Engineers, Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications, (ASME RA-S-2002), Addenda RA-Sb-2005, December 2005

19. Process for Performing Internal Events PRA Peer Reviews Using the ASME/ANS PRA Standard, NEI 05-04, Revision 2, November 2008

20. 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," American Society of Mechanical Engineers and American Nuclear Society, 2009

21. Letter from SNC (M.J. Ailuni) to NRC (Document Control Desk), "Joseph M. Farley Nuclear Plant License Amendment Request to Adopt NFPA 805 Performance Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants," dated September 25, 2012 (NL-12-1893)

22. Letter from NRC (S. Williams) to SNC (C. R. Pierce), "Joseph M. Farley Nuclear Plant, Units 1 and 2 – Issuance of Amendment Regarding Transition to a Risk-Informed, Performance-Based Fire Protection Program in Accordance with 10 CFR 50.48(c) (TAC Nos. ME9741 and ME9742)," Enclosure 3, "Safety Evaluation by the Office of Nuclear

Reactor Regulation," "Transition to a Risk-Informed Performance-Based Fire Protection Program in Accordance with 10 CFR 50.48(c)," dated March 10, 2015 (ML14308A048)

23. Letter from NRC (S. Williams) to Virginia Electric Power Company (D. A. Heacock), "Surry Power Station, Units 1 and 2 – Issuance of Amendment Regarding the Containment Type A and Type C Leak Rate Tests (TAC Nos. MF2612 and MF2613)," dated July 3, 2014 (ML14148A235)

24. Letter from NRC (A. W. Dietrich) to Indiana Michigan Power Company (L. J. Weber), "Donald C. Cook Nuclear Plant, Units 1 and 2 – Issuance of Amendments Re: Containment Leakage Rate Testing Program, (TAC Nos. MF3568 and MF3569)," dated March 30, 2015 (ML15072A264)

25. Letter from NRC (T. A. Lamb) to First Energy Nuclear Operating Company (E. A. Larson), "Beaver Valley Power Station, Unit Nos. 1 and 2 – Issuance of Amendment Re: License Amendment Request to Extend Containment Leakage Rate Test Frequency (TAC Nos. MF3985 and MF3986)," dated April 8, 2015 (ML15078A058)

26. Letter from NRC (A. N. Chereskin) to Exelon Generation Company (G. H. Gellrich), "Calvert Cliffs Nuclear Power Plant, Unit Nos. 1 and 2 – Issuance of Amendments Re: Extension of Containment Leakage Rate Testing Frequency (TAC Nos. MF4898 and MF4899)," dated July 16, 2015 (ML15154A661)

27. Letter from NRC (R. Ennis) to Exelon Nuclear (B. C. Hanson), "Peach Bottom Atomic Power Station, Units 2 and 3 – Issuance of Amendments Re: Extension of Type A and Type C Leak Rate Test Frequencies (TAC Nos. MF5172 and MF5173)," dated September 8, 2015 (ML15196A559)

28. Letter from NRC (B. Singal) to R. Flores (Luminant), "Comanche Peak Nuclear Power Plant, Units 1 and 2 – Issuance of Amendments Re: Technical Specification Change for Extension of the Integrated Leak Rate Test Frequency from 10 to 15 Years (TAC Nos. MF5621 and MF5622)," dated December 30, 2015

29. Southern Nuclear Procedure: RIE-001, "Generation and Maintenance of Probabilistic Risk Assessment Models and Associated Updates"

30. Letter from SNC (C. R. Pierce) to NRC (Document Control Desk), "Joseph M. Farley Nuclear Plant – Unit 1, Proposed Alternative for the Fourth Interval Inservice Inspection (FNP-ISI-ALT-14, Version 1.0)," dated February 18, 2014 (ML14050A382)

31. Letter from NRC (R. J. Pascarelli) to SNC (C. R. Pierce), "Joseph M. Farley, Unit 1 – Alternative Request Regarding Containment Building Tendon Examination Schedule (TAC No. MF3488)," dated July 11, 2014 (ML14169A195)

32. NUREG-1825, "Safety Evaluation Report Related to the License Renewal of the Joseph M. Farley Nuclear Plant, Units 1 and 2, Docket Nos. 50-348 and 50-364," dated March 2005 (ML050630571)

33. Letter from NRC (J. A. Nakoski) to Southern Nuclear Operating Company (J. T. Gasser), "Joseph M. Farley Nuclear Plant, Units 1 and 2, Edwin I. Hatch Nuclear Plant, Units 1 and 2, and Vogtle Electric Generating Plant, Units 1 and 2 Re: Request for Alternative

Alignment of IWE/IWL Inspection Program Interval with Corresponding Plant ISI Program Intervals (TAC Nos. MC4870, MC4871, MC4872, MC4873, MC4874, and MC4875)," dated April 25, 2005 (ML051030199)

34. NUREG/CR-7153 Volume 4, Expanded Materials Degradation Assessment (EMDA): Aging of Concrete and Civil Structures, October 2004

Attachment 1

Evaluation of Rick Significance of Permanent ILRT Extension

Attachment 1
Farley Unit 1 and Unit 2

Permanent ILRT Interval Extension Risk Impact Assessment

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1 Purpose of Analysis

1.1 Purpose

The purpose of this analysis is to provide a risk assessment of extending the currently allowed containment Type A Integrated Leak Rate Test (ILRT) interval to a permanent fifteen years for Farley Unit 1 and Unit 2. The extension would allow for substantial cost savings as the ILRT could be deferred for additional scheduled refueling outages for the Farley plants. The risk assessment follows the guidelines from NEI 94-01 (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 as applied to ILRT interval extensions, and 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 21).

1.2 Background

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 the limiting containment leakage rate of 1La[1].

The basis for the current fifteen year test interval is provided in Section 11.0 of NEI 94-01, Revision 3-A, and was established in 2008. 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 assessments 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 Report 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 PWR

[1] La (percent/24 hours) is the maximum allowable leakage rate at pressure Pa (calculated peak containment internal pressure related to the design basis accident) as specified in the technical specifications.

plant (i.e., Surry) containment isolation failures contribute less than 0.1% to the latent risks from reactor accidents. Consequently, it is desirable to show that extending the ILRT interval will not lead to a substantial increase in risk from containment isolation failures for Farley Unit 1 and Unit 2.

The Guidance provided in Appendix H of EPRI Report No. 1009325, Revision 2-A, "*Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals,*" (Reference 21) for performing risk impact assessments in support of ILRT extensions 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.

1.3 Criteria

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. Therefore, the increase in the conditional containment failure probability (CCFP) that helps to ensure that the defense-in-depth philosophy is maintained is also calculated. Since the Type A test does not impact CDF, the relevant criterion is the change in 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) that helps to ensure that the defense-in-depth philosophy is maintained is also calculated. The criteria described below are taken from the NRC Final Safety Evaluation for NEI 94-01 and EPRI Report No. 1009325 (Reference 24).

Regarding CCFP, the NRC concluded that a small increase in CCFP should be defined as a value marginally greater than that accepted in previous one time fifteen year ILRT extension requests. To this end the NRC has endorsed a small increase in CCFP as an increase in CCFP be less than or equal to 1.5% (Reference 24).

In addition, the total annual risk (person rem/yr population dose) is examined to demonstrate the relative change in this parameter. The NRC concluded that for purposes of assessing the risk impacts of the Type A ILRT extension in accordance with the EPRI methodology, 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 (Reference 24).

2 Methodology

A simplified bounding analysis approach consistent with the EPRI approach is used for evaluating the change in risk associated with increasing the test interval to fifteen years. The approach is consistent with that presented in Appendix H of EPRI Report No. 1009325, Revision 2-A, "*Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals*" (Reference 21), EPRI TR-104285 (Reference 2), NUREG-1493 (Reference 6) and the Calvert Cliffs liner corrosion analysis (Reference 5). The analysis uses results from the current Farley Unit 1 and Unit 2 Level 2 PRA models to establish frequency of fission product release categories. This risk assessment is applicable to Farley Unit 1 and Unit 2.

The six (6) general steps of this assessment are as follows:

1. Quantify the baseline risk in terms of the frequency of events (per reactor year) for each of the eight containment release scenario types identified in the EPRI report No. 1009325, Revision 2-A (Reference 21).

2. Develop plant specific person-rem (population dose) per reactor year for each of the eight containment release scenario types from plant specific consequence analyses.

3. Evaluate the risk impact (i.e., the change in containment release scenario type frequency and population dose) of extending the ILRT interval to fifteen years.

4. Determine the change in risk in terms of Large Early Release Frequency (LERF) in accordance with RG 1.174 (Reference 4) and compare with the acceptance guidelines of RG 1.174.

5. Determine the impact of the ILRT interval extension on the Conditional Containment Failure Probability (CCFP) and the population dose and compare with the acceptance guidance of Reference 24.

6. Evaluate the sensitivity of the results to assumptions in the liner corrosion analysis, external events and to the fractional contribution of increased large isolation failures (due to liner breach) to LERF.

This approach is based on the information and approaches contained in the previously mentioned studies. Furthermore:

- Consistent with the other industry containment leak risk assessments, the Farley Unit 1 and Unit 2 assessment uses LERF and delta LERF in accordance with the risk acceptance

guidance of RG 1.174. Changes in population dose and conditional containment failure probability are also considered to show that defense-in-depth and the balance of prevention and mitigation is preserved.

- The evaluation for Farley Unit 1 and Unit 2 uses ground rules and methods to calculate changes in risk metrics that are similar to those used in Appendix H of EPRI Report No. 1009325, Revision 2-A, "*Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals*."

3 Ground Rules

The following ground rules are used in the analysis:

- The technical adequacy of the Farley Unit 1 and Unit 2 PRA models are consistent with the requirements of Regulatory Guide 1.200 as is relevant to this ILRT interval extension, and are documented in Appendix A of this report.

- The results of the current Farley Unit 1 and Unit 2 Level 1 and Level 2 Internal Events PRA model are used in this analysis to assess fission product release frequencies.

- It is appropriate to use the results of Farley Unit 1 and Unit 2 internal events PSA model as a gauge to effectively describe the risk change attributable to the ILRT extension. It is reasonable to assume that the impact from the ILRT extension (with respect to percent increases in population dose) will not substantially differ if fire and seismic events were to be included in the calculations.

- Dose results for the containment failures modeled in the PSA 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 Farley Unit 1 and Unit 2 compared to the NUREG/CR-4551 reference plant.

- Accident classes describing radionuclide release end states are defined consistent with EPRI methodology (Reference 2) and are summarized in Section 4.2.

- The representative containment leakage for Class 1 sequences is 1La. Class 3 accounts for increased leakage due to Type A inspection failures.

- The representative containment leakage for Class 3a sequences is 10La based on the previously approved methodology performed for Indian Point Unit 3 (Reference 8 and Reference 9).

- The representative containment leakage for Class 3b sequences is 100La based on the guidance provided in EPRI Report No. 1009325, Revision 2-A.

- The Class 3b is very conservatively categorized as LERF based on the previously approved methodology (References 8 and 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 on 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.

4 Inputs

This section summarizes the general resources available as input (Section 4.1) and the plant specific resources required (Section 4.2).

4.1 General Resources Available

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

- NUREG/CR-3539 (Reference 10)
- NUREG/CR-4220 (Reference 11)
- NUREG-1273 (Reference 12)
- NUREG/CR-4330 (Reference 13)
- EPRI TR-105189 (Reference 14)
- NUREG-1493 (Reference 6)
- EPRI TR-104285 (Reference 2)
- NUREG-1150 (Reference 15) and NUREG/CR-4551 (Reference 7)
- NEI Interim Guidance (Reference 3, Reference 17)
- Calvert Cliffs Liner Corrosion Analysis (Reference 5)
- EPRI Report No. 1009325, Revision 2-A, Appendix H (Reference 21)

The 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 LLRT test 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 bases for the consequence analysis of the ILRT interval extension for Farley Unit 1 and Unit 2. 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 fifteen year extension of the ILRT interval.

4.1.1 NUREG/CR-3539 (Reference 10)

Oak Ridge National Laboratory (ORNL) 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.

4.1.2 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 (2,000) LERs, ILRT reports and other related records to calculate the unavailability of containment due to leakage.

4.1.3 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.

4.1.4 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."

4.1.5 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 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.

4.1.6 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 three per ten years to one per twenty 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.

4.1.7 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 (8) classes of containment response to a core damage accident:

- Containment intact and isolated
- Containment isolation failures dependent upon the core damage accident
- Type A (ILRT) related containment isolation failures
- Type B (LLRT) related containment isolation failures
- Type C (LLRT) related containment isolation failures
- Other penetration related containment isolation failures
- Containment failures due to core damage accident phenomena
- 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 ..."

4.1.8 NUREG-1150 (Reference 15) and NUREG/CR 4551 (Reference 7)

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 Farley Unit 1 and Unit 2 Level 2 model end-states assigned to one of the NUREG/CR-4551 APBs, it is considered adequate to represent Farley Unit 1 and Unit 2. (The meteorology and site differences other than population are assumed not to play a significant role in this evaluation.)

4.1.9 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 17)

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.

4.1.10 Calvert Cliffs Response to Request for Additional Information Concerning the License Amendment for a One-Time Integrated Leakage Rate Test Extension (Reference 5)

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, dome and a concrete basemat, each with a steel liner. Licensees may consider approved LARs for one-time extensions involving containment types similar to their facility. The Farley Unit 1 and Unit 2 assessment has addressed the plant specific differences from the Calvert Cliffs design, and how the Calvert Cliffs methodology was adapted to address the specific design features.

4.1.11 EPRI Report No. 1009325, Revision 2-A, Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals (Reference 21)

This report provides a generally applicable assessment of the risk involved in extension of ILRT test intervals to permanent fifteen year intervals. Appendix H of this document provides guidance for performing plant specific supplemental risk impact assessments and builds on the previous 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.

The approach included in this guidance document is used in the Farley Unit 1 and Unit 2 assessments 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 Classes 3a and 3b scenarios in this analysis as described in Section 5.

4.2 Plant Specific Inputs

The plant specific information used to perform the Farley Unit 1 and Unit 2 ILRT Extension Risk Assessments include the following:

- Level 1 Model results
- Level 2 Model results
- Release category definitions used in the Level 2 Model
- Population within a 50 mile radius
- ILRT results to demonstrate adequacy of the administrative and hardware issues
- Containment failure probability data

4.2.1 Level 1 Model

The Level 1 PRA models that are used for Farley Unit 1 and Unit 2 are characteristic of the as-built plant. The current Farley Unit 1 and Unit 2 models are linked fault tree models, and were quantified with a total Core Damage Frequency (CDF) = 1.91E-05/yr for Unit 1 and a CDF = 1.75E-05/yr for Unit 2, using a truncation value of 1E-12.

4.2.2 Level 2 Model

The Level 2 Model that is used for Farley Unit 1 and Unit 2 was developed to calculate the LERF contribution as well as the other release categories evaluated in the model. Table 4-1 and Table 4-2 summarize the pertinent Farley Unit 1 and Unit 2 results in terms of release category (Reference 25).

Table 4-1: Farley Unit 1 and Unit 2 Level 2 LERF Release Categories and Frequencies

Release Category	Description	Unit 1 Frequency (/yr)(1)	Unit 2 Frequency (/yr)(1)
LERF01	Containment Failure following High Pressure (HP) Vessel Breach(VB)	0.00E+00	0.00E+00
LERF02	Containment Failure following HP VB	0.00E+00	0.00E+00
LERF03	Containment Failure following Low Pressure (LP) VB	0.00E+00	0.00E+00
LERF04	TI-SGTR – Thermally Induced Steam Generator Tube Rupture	4.44E-09	3.39E-09
LERF05	Containment Failure following LP VB	0.00E+00	0.00E+00
LERF06	PI-SGTR – Pressure Induced Steam Generator Tube Rupture	7.30E-11	6.23E-11
LERF07	Containment Failure following LP VB	0.00E+00	0.00E+00
LERF08	Loss of Isolation	3.34E-08	3.22E-08
LERF09	Containment bypass	9.37E-08	9.38E-08
LERF10	SBO & Containment Failure following LP VB	0.00E+00	0.00E+00
LERF11	SBO & Containment Failure following HP VB	0.00E+00	0.00E+00

Table 4-1: Farley Unit 1 and Unit 2 Level 2 LERF Release Categories and Frequencies			
Release Category	**Description**	**Unit 1 Frequency (/yr)(1)**	**Unit 2 Frequency (/yr)(1)**
LERF12	SBO & Containment Failure following LP VB	0.00E+00	0.00E+00
LERF13	SBO & TI-SGTR	1.98E-09	1.79E-09
LERF14	SBO & Containment Failure following LP VB	0.00E+00	0.00E+00
LERF15	SBO & PI-SGTR	3.40E-11	3.20E-11
LERF16	SBO & Containment Failure following LP VB	0.00E+00	0.00E+00
LERF17	SBO & Loss of Isolation	1.82E-09	1.51E-09
LERF18	SBO & Containment bypass	0.00E+00	0.00E+00
Total LERF Release Category Frequency (LERF01 through LERF18)		1.35E-07	1.33E-07

Notes:
1. These values were quantified using a truncation value of 1.00E-13.

Table 4-2 summarizes all of the Level 2 release categories and frequencies. The CDF including uncategorized releases is determined by adding together all Level 2 release categories.

Table 4-2: Farley Unit 1 and Unit 2 Level 2 Release Category Summaries and Frequencies			
Release Category	**Definition**	**Unit 1 Frequency (/yr)**	**Unit 2 Frequency (/yr)(1)**
INTACT	Containment Intact	1.79E-08	1.08E-08
SERF	Small Early Release	0.00E+00	0.00E+00
LATE	Late Release	1.90E-05	1.79E-05
LERF	Total Large Early Releases	1.35E-07	1.33E-07
CDF (including uncategorized releases)(2)		1.91E-05	1.75E-05

Notes:
1. These values were quantified using a truncation value of 1.00E-13.
2. This value was calculated as a sum of all release categories (INTACT, SERF, LATE, and LERF).

4.2.3 Population Dose Calculations

The population dose is calculated by using data provided in NUREG/CR-4551 and adjusting the results to reflect the demographics around Farley Unit 1 and Unit 2. Each of the release categories from Table 4-1 was associated with an applicable collapsed Accident Progression Bin (APB) from NUREG/CR-4551 (see below). The collapsed APBs are characterized by 5 attributes related to the accident progression. Unique combinations of the 5 attributes result in a set of 7 bins that are relevant to the analysis. The definitions of the 7 collapsed APBs are provided in NUREG/CR-4551 and are reproduced in Table 4-3 for reference purposes. Table 4-4

summarizes the calculated population dose for Surry, the reference plant, associated with each APB from NUREG/CR-4551.

Table 4-3: Summary Accident Progression Bin (APB) Descriptions (Reference 7)	
Summary APB Number	**Description**
1	CD, VB, Early CF, Alpha Mode Core damage occurs followed by a very energetic molten fuel-coolant interaction in the vessel; the vessel fails and generates a missile that fails the containment as well. Includes accidents that have an Alpha mode failure of the vessel and the containment except those follow Event V or an SGTR. It includes Alpha mode failures that follow isolation failures because the Alpha mode containment failure is of rupture size.
2	CD, VB, Early CF, RCS Pressure > 200 psia Core Damage occurs followed by vessel breach. Implies Early CF with the RCS above 200 psia when the vessel fails. Early CF means at or before VB, so it includes isolation failures and seismic containment failures at the start of the accident as well as containment failure at VB. It does not include bins in which containment failure at VB follows Event V or an SGTR, or Alpha mode failures.
3	CD, VB, Early CF, RCS Pressure < 200 psia Core damage occurs followed by vessel breach. Implies Early CF with the RCS below psia when the containment fails. It does not include bins in which the containment failure at VB or an SGTR, or Alpha mode failures.
4	CD, VB, Late CF Core Damage occurs followed by vessel breach. Includes accidents in which the containment was not failed or bypassed before the onset of core-concrete interaction (CCI) and in which the vessel failed. The failure mechanisms are hydrogen combustion during CCI, Basemat Melt-Through (BMT) in several days, or eventual overpressure due to the failure to provide containment heat removal in the days following the accident.
5	CD, Bypass Core Damage occurs followed by vessel breach. Includes Event V and SGTRs no matter what happens to the containment after the start of the accident. It also includes SGTRs that do not result in VB.
6	CD, VB, No CF Core Damage occurs followed by vessel breach. Includes accidents not evaluated in one of the previous bins. The vessel's lower head is penetrated by the core, but the containment does not fail and is not bypassed.
7	CD, No VB, No CF Core Damage occurs but is arrested in time to prevent vessel breach. Includes accident progressions that avoid vessel failures except those that bypass the containment. Most of the bins placed in this reduce bin have no containment failure as well as no VB. It also includes bins in which the containment is not isolated at the start of the accident and the core is brought to a safe stable state before the vessel fails.

Table 4-4: Calculation of Surry Population Dose Risk at 50 Miles (Reference 7)				
Collapsed Bin #	**Fractional APB Contributions to Risk (MFCR)** (1)	**NUREG/CR-4551 Population Dose Risk at 50 miles (person-rem/yr, mean)** (2)	**NUREG/CR-4551 Collapsed Bin Frequencies (per year)** (3)	**NUREG/CR-4551 Population Dose at 50 miles (person-rem)** (4)
1	0.029	0.158	1.23E-07	1.28E+06
2	0.019	0.106	1.64E-07	6.46E+05
3	0.002	0.013	2.012E-08	6.46E+05 (5)
4	0.216	1.199	2.42E-06	4.95E+05
5	0.732	4.060	5.00E-06	8.12E+05
6	0.001	0.006	1.42E-05	4.23E+02
7	0.002	0.011	1.91E-05	5.76E+02
Totals	1.000	5.55	4.1E-05	

Notes:

(1) Mean Fractional Contribution to Risk calculated from the average of two samples delineated in Table 5.1-3 of NUREG/CR-4551.
(2) The total population dose risk at 50 miles from internal events in person-rem is provided as the average of two samples in Table 5.1-1 of NUREG/CR-4551. The contribution for a given APB is the product of the total PDR50 and the fractional APB contribution.
(3) NUREG/CR-4551 provides the conditional probabilities of the collapsed APBs in Figure 2.5-3. These conditional probabilities are multiplied by the total internal CDF to calculate the collapsed APB frequency.
(4) Obtained from dividing the population dose risk shown in the third column of this table by the collapsed bin frequency shown in the fourth column of this table.
(5) Assumed population dose at 50 miles for Collapsed Bin #3 equal to that of Collapsed Bin #2. Collapsed Bin Frequency #3 was then back calculated using that value. This does not influence the results of this evaluation since Bin #3 does not appear as part of the results for Farley Unit 1 and Unit 2.

4.2.4 Population Dose Estimate Methodology

The person-rem results in Table 4-4 can be used as an approximation of the dose for Farley Unit 1 and Unit 2 if it is corrected for allowable containment leak rate (La), reactor power level and the population density surrounding Farley.

La adjustment:

$$F_{Leakage} = \frac{\text{La of Farley Unit 1 and Unit 2 (\%w/o/day)}}{\text{La of reference plant (applicable only to those APBs affected by normal leakage)}}$$

La for Farley Unit 1 and Unit 2 is 0.15%w/o/day (Reference 25). La for Surry is 0.1%w/o/day.

$F_{Leakage} = 0.15 / 0.1$

$F_{Leakage} = 1.5$

Power level adjustment:

$$F_{Power} = \frac{\text{Rated power level of Farley Unit 1 and Unit 2 (MWt)}}{\text{Rated power level of reference plant (MWt)}}$$

The rated power level for Farley Unit 1 and Unit 2 is 2775 MWt (Reference 25). The rated power level for Surry is 2441MWt.

$F_{Power} = 2775 \text{ MWt} / 2441 \text{ MWt}$

$F_{Power} = 1.137$

Population density adjustment:

The total population within a 50 mile radius of Farley Unit 1 and Unit 2 is 6.598E+05 (Reference 25). This population value is compared to the population value that is provided in NUREG/CR-4551 in order to get a "Population Dose Factor" that can be applied to the APBs to get dose estimates for Farley Unit 1 and Unit 2. Note that the numbers reported below may represent a rounded result as displayed in the attached spreadsheets.

Total Farley Unit 1 and Unit 2 Population within 50 miles = 6.598E+05

Surry Population within a 50 mile radius from the NUREG/CR-4551 reference plant = 1.23E+06

$F_{Population} = 6.598E+05 / 1.23E+06 = 0.536$

The factors developed above are used to adjust the population dose for the surrogate plant (Surry) for Farley Unit 1 and Unit 2. For intact containment endstates, the total population dose factor is as follows:

$F_{Intact} = F_{Population} * F_{Power} * F_{Leakage}$

$F_{Intact} = 0.536 * 1.137 * 1.5$

$F_{Intact} = 0.915$

For EPRI accident classes not dependent on containment leakage, the population dose factor is as follows:

$F_{Others} = F_{Population} * F_{Power}$

$F_{Others} = 0.536 * 1.137$

$F_{Others} = 0.610$

The difference in the doses at 50 miles is assumed to be in direct proportion to the difference in the population within 50 miles of each site. The above adjustments provide an approximation for Farley Unit 1 and Unit 2 of the population doses associated with each of the release categories from NUREG/CR-4551.

Table 4-5 shows the results of applying the population dose factor to the NUREG/CR-4551 population dose results at 50 miles to obtain the adjusted population dose at 50 miles for Farley Unit 1 and Unit 2.

Table 4-5: Calculation of Farley Unit 1 and Unit 2 Population Dose Risk at 50 Miles

Accident Progression Bin (APB)	NUREG/CR-4551 Population Dose at 50 miles (person-rem)	Bin Multiplier used to obtain Farley Population Dose		Farley Adjusted Population Dose at 50 miles (person-rem)
1	1.28E+06	F_{Other}	0.610	7.81E+05
2	6.46E+05	F_{Other}	0.610	3.94E+05
3	6.46E+05	F_{Other}	0.610	3.94E+05
4	4.95E+05	F_{Other}	0.610	3.02E+05
5	8.12E+05	F_{Other}	0.610	4.95E+05
6	4.23E+02	F_{Intact}	0.915	3.87E+02
7	5.76E+02	F_{Intact}	0.915	5.27E+02

4.2.5 Application of Farley Unit 1 and Unit 2 PRA Model Results to NUREG/CR-4551 Level 3 Output

A major factor related to the use of NUREG/CR-4551 in this evaluation is that the results of the Farley Unit 1 and Unit 2 PRA Level 2 models are not defined in the same terms as reported in NUREG/CR-4551. In order to use the Level 3 model presented in that document, it was necessary to match the Farley PRA Level 2 release categories to the collapsed APBs. The assignments are shown in Table 4-6, along with the corresponding EPRI classes (see below). The EPRI classes and descriptions are listed in Table 4-7 in addition to the Farley Level 2 release categories.

Table 4-6: Farley Unit 1 and Unit 2 Level 2 Model Assumptions for Application to the NUREG/CR-4551 Accident Progression Bins and EPRI Accident Classes

Farley Level 2 Release Category	Unit 1 Frequency (per yr)	Unit 2 Frequency (per yr)	Definition	NUREG/CR-4551 APB	EPRI Class

Table 4-6: Farley Unit 1 and Unit 2 Level 2 Model Assumptions for Application to the NUREG/CR-4551 Accident Progression Bins and EPRI Accident Classes					
Farley Level 2 Release Category	**Unit 1 Frequency (per yr)**	**Unit 2 Frequency (per yr)**	**Definition**	**NUREG/CR-4551 APB**	**EPRI Class**
INTACT	1.79E-08	1.08E-08	Containment Intact	6,7	1
SERF	0.00E+00	0.00E+00	Small Early Release	3	3
LATE01	9.47E-07	1.94E-06	Late Release with Basemat Melt-through	4	1
LATE02	2.52E-07	1.37E-07	Late Release from Containment Overpressure	4	7
LATE03	3.19E-08	2.63E-08	Late Release from Containment Overpressure	4	7
LATE04	9.85E-07	6.24E-07	Late Release with Basemat Melt-through	4	1
LATE05	1.66E-06	1.34E-06	Late Release from Containment Overpressure	4	7
LATE06	4.98E-07	3.25E-07	Late Release with Basemat Melt-through	4	1
LATE07	1.93E-07	1.64E-07	Late Release from Containment Overpressure	4	7
LATE08	7.92E-06	8.33E-06	Late Release with Basemat Melt-through	4	1
LATE09	4.21E-06	3.40E-06	Late Release from Containment Overpressure	4	7
LATE10	4.84E-07	9.84E-08	SBO & Containment Overpressure	4	7
LATE11	2.29E-08	2.05E-08	SBO & Containment Overpressure	4	7
LATE12	1.23E-06	1.10E-06	SBO & Containment Overpressure	4	7
LATE13	1.31E-07	1.17E-07	SBO & Containment Overpressure	4	7
LATE14	4.11E-07	2.90E-07	SBO & Containment Overpressure	4	7
LERF01	0.00E+00	0.00E+00	Non-SBO with a Low Pressure CFE	3	7
LERF02	0.00E+00	0.00E+00	Non-SBO with a High Pressure CFE	2	7
LERF03	0.00E+00	0.00E+00	Non-SBO with a Low Pressure CFE	3	7
LERF04	4.44E-09	3.39E-09	Non-SBO with a TI-SGTR	5	8
LERF05	0.00E+00	0.00E+00	Non-SBO with a Low Pressure CFE	3	7
LERF06	7.30E-11	6.23E-11	Non-SBO with a PI-SGTR	5	8
LERF07	0.00E+00	0.00E+00	Non-SBO with a Low Pressure CFE	3	7
LERF08	3.34E-08	3.22E-08	Non-SBO with Containment Isolation Failure	1	2
LERF09	9.37E-08	9.38E-08	Non-SBO with a Large Bypass Event	5	8
LERF10	0.00E+00	0.00E+00	SBO with a Low Pressure CFE	3	7
LERF11	0.00E+00	0.00E+00	SBO with a High Pressure CFE	2	7
LERF12	0.00E+00	0.00E+00	SBO with a Low Pressure CFE	3	7
LERF13	1.98E-09	1.79E-09	SBO with a TI-SGTR	5	8
LERF14	0.00E+00	0.00E+00	SBO with a Low Pressure CFE	3	7
LERF15	3.40E-11	3.20E-11	SBO with a PI-SGTR	5	8

Table 4-6: Farley Unit 1 and Unit 2 Level 2 Model Assumptions for Application to the NUREG/CR-4551 Accident Progression Bins and EPRI Accident Classes					
Farley Level 2 Release Category	**Unit 1 Frequency (per yr)**	**Unit 2 Frequency (per yr)**	**Definition**	**NUREG/CR-4551 APB**	**EPRI Class**
LERF16	0.00E+00	0.00E+00	SBO with a Low Pressure CFE	3	7
LERF17	1.82E-09	1.51E-09	SBO with Containment Isolation Failure	1	2
LERF18	0.00E+00	0.00E+00	SBO with a Large Bypass Event	5	8

4.2.6 Release Category Definitions

Table 4-7 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 of this report.

Table 4-7: EPRI Containment Failure Classification (Reference 2)		
Class	**Description**	**Farley Level 2 Release Category**
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 La, under Appendix J for that plant	INTACT01 through INTACT10 and LATE01, LATE04, LATE06, LATE08[(1)]
2	Containment isolation failures (as reported in the IPEs) include those accidents in which there is a failure to isolate the containment.	LERF08 & LERF17
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.	SERF
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.	N/A

Table 4-7: EPRI Containment Failure Classification (Reference 2)		
Class	**Description**	**Farley Level 2 Release Category**
5	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 4 isolation failures, but is applicable to sequences involving Type C tests and their potential failures.	N/A
6	Containment isolation failures include those leak paths covered in the plant test and maintenance requirements or verified per in service inspection and testing (ISI/IST) program.	N/A
7	Accidents involving containment failure induced by severe accident phenomena. Changes in Appendix J testing requirements do not impact these accidents.	LERF01, LERF02, LERF03, LERF05, LERF07, LERF10, LERF11, LERF12, LERF14, LERF16, LATE02, LATE03, LATE05, LATE07, LATE09, LATE10 through, LATE14
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.	Containment Bypass (LERF09 and LERF18) and SGTR (LERF04, LERF06, LERF13 and LERF15)

Notes:

1. Note that EPRI Class 1 includes four release categories that include release categories involving basemat melt-through (BMMT). Scenarios involving BMMT are vulnerable to large early releases from undetected leakage similar to sequences where the containment remains intact.

4.3 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 bellow 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 accounted for, the EPRI Class 3 accident class as defined in Table 4-6, it 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 3b failures is determined consistent with the EPRI Guidance (Reference 21). 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 2/217=0.0092). For Class 3b, Jefferys non-informative prior distribution is assumed for no "large" failures in 217 tests (i.e., 0.5 / (217+1) = 0.0023).

In a follow on letter (Reference 17) 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. This additional NEI information includes a discussion of conservatisms in the quantitative guidance for delta LERF. NEI describes ways to demonstrate that, using plant specific calculations, the delta LERF 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 Farley Unit 1 and Unit 2, as detailed in Section 5, involves the following:

- The Class 2 and Class 8 sequences are subtracted 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. Class 2 and Class 8 events refer to sequences with either large preexisting containment isolation failures or containment bypass events. These sequences are already considered to contribute to LERF in the Farley Unit 1 and Unit 2 Level 2 PRA analyses.

- Class 1 accident sequences may involve availability and or successful operation of containment sprays. It could be assumed that, for calculation of the Class 3b and 3a frequencies, the fraction of the Class 1 CDF associated with successful operation of containment sprays can also be subtracted. However, in this assessment Farley Unit 1 and Unit 2 do not credit containment spray as a means of reducing releases from Class 3 events.

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 yr/2), and the average time that a leak could exist without detection for a ten year interval is five years (10 yr/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. An extension of the ILRT interval to fifteen years can be estimated to lead to about a factor of 5.0 (7.5/1.5) increase in the non-detection probability of a leak compared to a three year interval.

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.

4.4 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 the methodology from the Calvert Cliffs liner corrosion analysis (Reference 5). The Calvert Cliffs analysis was performed for a concrete cylinder, dome and a concrete basemat, each with a steel liner. Farley Unit 1 and Unit 2 have a similar containment.

The following approach is used to determine the change in likelihood, due to extending the ILRT, of detecting corrosion of a containment steel liner. 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 upper containment (cylinder and dome regions in Calvert Cliffs evaluation)
- 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

4.4.1 Assumptions

- Consistent with the Calvert Cliffs analysis, a half failure is conservatively assumed for basemat concealed liner corrosion due to the lack of identified failures (See Table 4-8, Step 1).
- There are two corrosion events used to estimate the liner flaw probability in the Calvert Cliffs analysis. These events are assumed to be applicable to this Farley Unit 1 and Unit 2 containment analysis. These events, one at North Anna Unit 2 and one at Brunswick Unit 2, were initiated from the nonvisible (backside) portion of the containment liner.
- Consistent with the Calvert Cliffs analysis, the estimated historical flaw probability is based on 70 steel-lined containments.
- The Calvert Cliffs analysis used the estimated historical liner flaw probability of 5.5 years to reflect the years since September 1996 when 10CFR50.55a 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. Since the time of the Calvert Cliffs submittal, two additional relevant liner corrosion events involving concealed

corrosion (corrosion initiated on the inaccessible liner surface) were observed and are considered in the corrosion risk assessment. These events occurred at Beaver Valley Unit 1 and D.C. Cook Unit 2 (Reference 22 and Reference 23, respectively). Consistent with the addition of the two observed events, the historical liner flaw probability was established by incrementing the flaw observation time by 7.75 years. This re-evaluation resulted in a reduction of the historical liner flaw likelihood to 4.3E-03/year ((2+2) / [70 * (5.5 + 7.75)] = 4.3E-03/year). This value is smaller than the value of 5.2E-03 which is used in the Calvert Cliffs analysis. The conservative value of 5.2E-03 will be used in this Farley Unit 1 and Unit 2 report to remain consistent with the Calvert Cliffs analysis.

- Consistent with the Calvert Cliffs analysis, the steel plate 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 ages. (See Table 4-8, 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, and the selected values are consistent with a pressure that corresponds to the ILRT target pressure of 37 psig. For Farley Unit 1 and Unit 2, the containment failure probabilities are less than these values at 37 psig based on the containment fragility curve which is documented in the Farley Unit 1 and Unit 2 Level 2 analyses. A containment bypass model is utilized for LERF. Conservative probabilities of 1% for an existing through wall flaw to be present on the shell above the basemat and 0.1% for the basemat are used in this analysis, and sensitivity studies are included that increase and decrease the probabilities by an order of magnitude (See Table 4-8, 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 upper containment region (See Table 4-8, 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 4-8, Step 5). Sensitivity studies are included that evaluate total detection failure likelihood of 5% and 15%, respectively.

- 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.

4.4.2 Analysis

Table 4-8: Steel Liner Corrosion Base Case					
Step	**Description**	**Upper Containment**		**Containment Basemat**	
1	**Historical Steel Liner Flaw Likelihood** Failure Data: Containment location specific	Events: 2 (2)/(70 * 5.5) = **5.2E-03**		Events: 0 (assume half a failure) 0.5/(70 * 5.5) = **1.3E-03**	
2	**Age Adjusted Steel Liner Flaw Likelihood** During 15-year interval, assume failure rate doubles every five years (14.9% increase per year). The average for 5th to 10th year is set to the historical failure rate (consistent with Calvert Cliffs analysis).	Year 1 avg 5-10 15	Failure Rate 2.1E-03 5.2E-03 1.4E-02	Year 1 avg 5-10 15	Failure Rate 5.0E-04 1.3E-03 3.5E-03
		15 year average = 6.27E-03		**15 year average = 1.57E-03**	
3	**Flaw Likelihood at 3, 10, and 15 years** Uses age adjusted liner flaw likelihood (Step 2), assuming failure rate doubles every five years (consistent with Calvert Cliffs analysis – See Table 6 of Reference 5).	**0.71% (1 to 3 years)** **4.06% (1 to 10 years)** **9.40% (1 to 15 years)** (Note that the Calvert Cliffs analysis presents the delta between 3 and 15 years of 8.7% to utilize in the estimation of the delta-LERF value. For this analysis, however, the values are calculated based on the 3, 10, and 15 year intervals consistent with the intervals of concern in this analysis.)		**0.18% (1 to 3 years)** **1.02% (1 to 10 years)** **2.35% (1 to 15 years)** (Note that the Calvert Cliffs analysis presents the delta between 3 and 15 years of 2.2% to utilize in the estimation of the delta-LERF value. For this analysis, however, the values are calculated based on the 3, 10, and 15 year intervals consistent with the intervals of concern in this analysis.)	
4	**Likelihood of Breach in Containment Given Steel Liner Flaw** The failure probability of the cylinder and dome is assumed to be 1% (compared to 1.1% in the Calvert Cliffs analysis). The basemat failure probability is assumed to be a factor of ten less, 0.1%, (compared to 0.11% in the Calvert Cliffs analysis).	**1%**		**0.1%**	

4.4.3

5	**Visual Inspection Detection Failure Likelihood** Utilize assumptions consistent with Calvert Cliffs analysis.	**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 * 4* 5)	**0.00071% (at 3 years)** 0.71% * 1% * 10% **0.0041% (at 10 years)** 4.1% * 1% * 10% **0.0094% (at 15 years)** 9.4% * 1% * 10%	**0.00018% (at 3 years)** 0.18% * 0.1% * 100% **0.0010% (at 10 years)** 1.0% * 0.1% * 100% **0.0024% (at 15 years)** 2.4% * 0.1% * 100%

The total likelihood of the corrosion-induced, non-detected containment leakage is the sum of Step 6 for the leakages for the upper containment and the containment basemat as summarized below for Farley Unit 1 and Unit 2.

Total Likelihood of Non-Detected Containment Leakage Due To Corrosion for Farley Unit 1 and Unit 2:

At 3 years: 0.00071% + 0.00018% = 0.00089%

At 10 years: 0.0041% + 0.0010% = 0.0051%

At 15 years: 0.0094% + 0.0024% = 0.012%

The above factors are applied to those core damage accidents that are not already independently LERF or that could never result in LERF. For example, the three in ten year case is calculated as follows:

(1) The Farley Unit 1 and Unit 2 CDF associated with accidents that are not independently LERF or could never result in LERF are Level 2 Release Categories INTACT, SERF and LATE. Per Table 4-2, the Farley Unit 1 and Unit 2 CDF associated with accidents that are not independently LERF or could never result in LERF is equal to 1.79E-08/yr + 0.00E+00/yr + 1.90E-05/yr = 1.90E-05/yr for Unit 1, and 1.08E-08 /yr + 0.00E+00/yr + 1.79E-05/yr = 1.79E-05 /yr for Unit 2.

(2) Per Table 5-3, the EPRI Class 3b frequency is 4.36E-08/yr for Unit 1 and 4.00E-08 for Unit 2.

(3) The increase in the base case Class 3b frequency due to the corrosion-induced concealed flaw issue for Unit 1 is calculated as 1.90E-05/yr * 0.00089% = 1.69E-10/yr, where

0.00089% was previously shown above to be the cumulative likelihood of non-detected containment leakage due to corrosion at three years. The increase in the base case Class 3b frequency due to the corrosion-induced concealed flaw issue for Unit 2 is calculated as 1.79E-05/yr * 0.00089% = 1.60E-10/yr, where 0.00089% was previously shown above to be the cumulative likelihood of non–detected containment leakage due to corrosion at three years

(4) The three in ten year Class 3b frequency including the corrosion-induced concealed flaw issue is then calculated as 4.36E-08 /yr + 1.69E-10E-10/yr = 4.38E-08/yr for Unit 1 and 4.00E-08/yr + 1.60E-10/yr =4.01E-08 for Unit 2.

5 Results

The application of the approach based on the guidance contained in EPRI Report No. 1009325, Revision 2-A, Appendix H, EPRI-TR-104285 (Reference 2) and previous risk assessment submittals on this subject (References 5, 8, 18, 19, and 20) have led to the following results. The results are displayed according to the eight accident classes defined in the EPRI report. Table 5-1 lists these accident classes.

The analysis performed examined Farley Unit 1 and Unit 2 specific accident sequences in which the containment remains intact or the containment is impaired. Specifically, the breakdown of the severe accidents contributing to risk is considered in the following manner:

(1) Core damage sequences in which the containment remains intact initially and in the long term (EPRI TR-104285 Class 1 sequences).

(2) 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 bellows leakage. (EPRI TR-104285 Class 3 sequences).

(3) Core damage sequences in which containment integrity is impaired due to containment isolation failures of pathways left "opened" following a plant post-maintenance test. (For example, a valve failing to close following a valve stroke test. (EPRI TR-104285 Class 6 sequences). Consistent with the NEI Guidance, this class is not specifically examined since it will not significantly influence the results of this analysis.

(4) Accident sequences involving containment bypassed (EPRI TR-104285 Class 8 sequences), large containment isolation failures (EPRI TR-104285 Class 2 sequences), and small containment isolation "failure-to-seal" events (EPRI TR-104285 Class 4 and 5 sequences) are accounted for in this evaluation as part of the baseline risk profile. However, they are not affected by the ILRT frequency change.

(5) 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 5-1: Accident Classes	
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 base-line risk in terms of frequency per reactor year for each of the eight accident classes presented in Table 5-1.

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 three to fifteen and ten to fifteen years.

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

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

5.1 Step 1 - Quantify the Base-Line 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 TR-104285). 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 5-1 were developed for Farley Unit 1 and Unit 2 by first determining the frequencies for Classes 1, 2, 7 and 8 using the

categorized sequences and the identified correlations shown in Table 4-6, scaling these frequencies to account for the uncategorized sequences, determining the frequencies for Classes 3a and 3b, and then determining the remaining frequency for Class 1. Furthermore, adjustments were made to the Class 3b and hence Class 1 frequencies to account for the impact of undetected corrosion per the methodology described in Section 4.4.

For Farley Unit 1, as noted in Table 5-2, the total frequency of the categorized sequences is 1.91E-05/yr, the total CDF is 1.91E-05/yr, and the scaling factor is 0.998. For Farley Unit 2, as noted in Table 5 2, the total frequency of the categorized sequences is 1.81E-05/yr, the total CDF is 1.75E-05/yr, and the scaling factor is 0.969. The scaling factor for Unit 1 is determined by dividing the total core damage frequency (including the uncategorized frequency) by the total categorized release category frequency (1.910E-05/yr / 1.913E-05/yr = 0.998). The scaling factor for Unit 2 is determined by dividing the total core damage frequency (including the uncategorized frequency) by the total categorized release category frequency (1.75E-05/yr / 1.81E-05/yr = 0.969).

Table 5-2: Farley Unit 1 and Unit 2 Categorized Accident Classes and Frequencies					
EPRI Class	**Farley Unit 1 and Unit 2 Release Category**	**Unit 1**		**Unit 2**	
		Frequency Based on Categorized Results (per yr)	**Adjusted Frequency Using Scale Factor of 0.998 (per yr)**	**Frequency Based on Categorized Results (per yr)**	**Adjusted Frequency Using Scale Factor of 0.969 (per yr)**
1	Intact containment (INTACT01 through INTACT10 and LATE01, LATE04, LATE06, LATE08)	1.04E-05	1.04E-05	1.12E-05	1.09E-05
2	Containment Isolation failures (LERF08 & LERF17)	3.52E-08	3.52E-08	3.37E-08	3.27E-08
7	Containment Failure (LERF01, LERF02, LERF03, LERF05, LERF07, LERF10, LERF11, LERF12, LERF14, LERF16, LATE02, LATE03, LATE05, LATE07, LATE09, LATE10 through, LATE14)	8.63E-06	8.61E-06	6.69E-06	6.48E-06
8	Containment Bypass (LERF09 and LERF18) and SGTR (LERF04, LERF06, LERF13 and LERF15)	1.00E-07	1.00E-07	9.90E-08	9.60E-08
Total Frequency		1.91E-05	1.91E-05	1.81E-05	1.75E-05

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 frequency per year is initially determined from the Level 2 Release Category listed in Table 5-2 minus the EPRI Class 3a and 3b frequency, which are calculated below.

Class 2 Sequences. This group consists of all core damage accident progression bins for which a failure to isolate the containment occurs. The frequency per year for these sequences is obtained from the Containment Isolation Failures listed in Table 5-2.

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. The containment leakage for these sequences can be either small (in excess of design allowable but <10La) or large (>100La).

The respective frequencies per year are determined as follows:

$PROB_{class\_3a}$ = probability of small pre-existing containment liner leakage

= 0.0092 [see Section 4.3]

$PROB_{class\_3b}$ = probability of large pre-existing containment liner leakage

= 0.0023 [see Section 4.3]

As described in Section 4.3, additional consideration is made to not apply these failure probabilities on those cases that are already LERF scenarios (i.e., the Class 2 and Class 8 contributions).

Class 3a Frequency (Unit 1) = 0.0092 * (CDF - (Class 2 + Class 8))

= 0.0092 * (1.91E-05/yr – (3.52E-07/yr + 1.00E-07/yr)) = 1.74E-07/yr

Class 3b Frequency (Unit 1) = 0.0023 * (CDF - (Class 2 + Class 8))

=0.0023 * (1.91E-05/yr – (3.52E-07/yr + 1.00E-07/yr)) = 4.36E-08/yr

Class 3a Frequency (Unit 2) = 0.0092 * (CDF - (Class 2 + Class 8))

= 0.0092 * (1.75E-05/yr – (3.27E-08/yr + 9.60E-08/yr)) = 1.60E-07/yr

Class 3b Frequency (Unit 2) = 0.0023 * (CDF - (Class 2 + Class 8))

=0.0023 * (1.75E-05/yr – (3.27E-08/yr + 9.60E-08/yr)) = 4.00E-08/yr

For this analysis, the associated containment leakage for Class 3a is 10La and for Class 3b is 100La. These assignments are consistent with the guidance provided in EPRI Report No. 1009325, Revision 2-A.

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.

Class 5 Sequences. This group consists of all core damage accident progression bins for which 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.

Class 6 Sequences. This group is similar to Class 2. 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, typically resulting in a failure to close smaller containment isolation valves. All other failure modes are bounded by the Class 2 assumptions. Consistent with guidance provided in EPRI Report No. 1009325, Revision 2-A, this accident class is not explicitly considered since it has a negligible impact on the results.

Class 7 Sequences. This group consists of all core damage accident progression bins in which containment failure induced by severe accident phenomena occurs (e.g., overpressure). For this analysis, the frequency is determined from the Severe Accident Phenomena-Induced Failures Release Categories from the Farley Unit 1 and Unit 2 Level 2 results shown in Table 5-2.

Class 8 Sequences. This group consists of all core damage accident progression bins in which containment bypass occurs. For this analysis, the frequency is determined from the Containment Bypass and SGTR Release Categories from the Farley Unit 1 and Unit 2 Level 2 results shown in Table 5-2.

5.1.1 Summary of Accident Class Frequencies

In summary, the accident sequence frequencies that can lead to radionuclide release to the public have been derived consistent with the definitions of accident classes defined in EPRI-TR-104285 the NEI Interim Guidance, and guidance provided in EPRI Report No. 1009325, Revision 2-A. Table 5-3 summarizes these accident frequencies by accident class for Farley Unit 1 and Unit 2.

Table 5-3: Radionuclide Release Frequencies as a Function of Accident Class (Farley Unit 1 and Unit 2 Base Case)					
Accident Classes (Containment Release Type)	**Description**	**Unit 1 Frequency (per Rx-yr)**		**Unit 2 Frequency (per Rx-yr)**	
		EPRI Methodology	**EPRI Methodology Plus Corrosion(1)**	**EPRI Methodology**	**EPRI Methodology Plus Corrosion**
1	No Containment Failure	1.01E-05	1.01E-05	1.07E-05	1.07E-05
2	Large Isolation Failures (Failure to Close)	3.52E-08	3.52E-08	3.27E-08	3.27E-08
3a	Small Isolation Failures (liner breach)	1.74E-07	1.74E-07	1.60E-07	1.60E-07
3b	Large Isolation Failures (liner breach)	4.36E-08	4.38E-08	4.00E-08	4.01E-08
4	Small Isolation Failures (Failure to seal –Type B)	N/A	N/A	N/A	N/A
5	Small Isolation Failures (Failure to seal—Type C)	N/A	N/A	N/A	N/A
6	Other Isolation Failures (e.g., dependent failures)	N/A	N/A	N/A	N/A
7	Failures Induced by Phenomena (Early and Late)	8.61E-06	8.61E-06	6.48E-06	6.48E-06
8	Bypass (Interfacing System LOCA)	1.00E-07	1.00E-07	9.60E-08	9.60E-08
CDF	All CET end states	1.91E-05	1.91E-05	1.75E-05	1.75E-05

Notes:

1. Note that this is based on data developed in Section 4.4. Only Classes 1 and 3b are impacted by the corrosion.

5.2 Step 2 - Develop Plant Specific Person-Rem Dose (Population Dose) Per Reactor Year

Plant specific release analyses were performed to estimate the person-rem doses to the population within a 50 mile radius from the plant, and summarized in Table 4-5. The results of applying these releases to the EPRI containment failure classification are as follows:

Class 1 = 4.57E+02 person-rem (Note 1)

Class 2 = 3.94E+05 person rem (Note 2)

Class 3a = 4.57E+02 person-rem x 10La = 4.57E+03 person-rem (Note 3)

Class 3b = 4.57E+02 person-rem x 100La = 4.57E+04 person-rem (Note 3)

Class 4 = Not analyzed

Class 5 = Not analyzed

Class 6 = Not analyzed

Class 7 = 3.02E+05 person rem (Note 4)

Class 8 = 4.95E+05 person-rem (Note 5)

Notes:

1. The derivation is described in Section 4.2 for Farley Unit 1 and Unit 2. Class 1 is assigned the dose from the "no containment failure" APBs from NUREG/CR-4551 (i.e., APB #6 and APB #7). The dose is calculated as an arithmetic average of the dose for these bins and is bounding[2].
2. The Class 2, containment isolation failures, dose is assigned from APB #2 (Early CF).
3. The Class 3a and 3b dose are related to the Class 1 leakage rate as shown. While no pre-existing leakage in excess of 21 La has been identified for any historical ILRT event, Class 3b releases are conservatively assessed at 100La. Class 3a releases are conservatively assessed at 10La. This is consistent with the guidance provided in EPRI Report No. 1009325, Revision 2-A.
4. The Class 7 dose is assigned from APB #4 (Late CF).
5. Class 8 sequences involve containment bypass failures; as a result, the person-rem dose is not based on normal containment leakage. The releases for this class are assigned from APB #5 (Bypass).

In summary, the population dose estimates derived for use in the risk evaluation per the EPRI methodology (Reference 2) containment failure classifications, and consistent with the NEI guidance (Reference 3) as modified by EPRI Report No. 1009325, Revision 2-A are provided in Table 5-4.

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[2] The use of a simple average dose is bounding as the average over-estimates the proportion of endstates that initiated with a pre-existing isolation failure (APB #7) in the Farley Level 2 model.

Table 5-4: Farley Unit 1 and Unit 2 Population Dose Estimates for Population Within 50 Miles		
Accident Classes (Containment Release Type)	**Description**	**Unit 1 and Unit 2 Person-Rem (50 miles)**
1	No Containment Failure	4.57E+02
2	Large Isolation Failures (Failure to Close)	3.94E+05
3a	Small Isolation Failures (liner breach)	4.57E+03
3b	Large Isolation Failures (liner breach)	4.57E+04
4	Small Isolation Failures (Failure to seal-Type B)	N/A
5	Small Isolation Failures (Failure to seal-Type C)	N/A
6	Other Isolation Failures (e.g., dependent failures)	N/A
7	Failures Induced by Phenomena (Early and Late)	3.02E+05
8	Bypass (Interfacing System LOCA)	4.95E+05

The above dose estimates, when combined with the results presented in Table 5-3, yield the Farley Unit 1 and Unit 2 baseline mean consequence measures for each accident class. These results are presented in Table 5-5 for Unit 1 and Table 5-6 for Unit 2. (Note that the values for "Change due to corrosion - person-rem/yr" for Class 1 are negative, due to the removal of Class 3a and 3b frequencies from Class 1.)

Table 5-5: Farley Unit 1 Annual Dose as a Function of Accident Class; Characteristic of Conditions for ILRT Required 3/10 Years							
Accident Classes (Cnmt Release Type)	Description	Person-Rem (50 miles)	EPRI Methodology		EPRI Methodology Plus Corrosion		Change Due to Corrosion Person-Rem/yr(1)
			Frequency (per Rx-yr)	Person-Rem/yr (50 miles)	Frequency (per Rx-yr)	Person- Rem/yr (50 miles)	
1	No Containment Failure(2)	4.57E+02	1.01E-05	4.63E-03	1.01E-05	4.63E-03	-7.73E-08
2	Large Isolation Failures (Failure to Close)	3.94E+05	3.52E-08	1.39E-02	3.52E-08	1.39E-02	0.00E+00
3a	Small Isolation Failures (liner breach)	4.57E+03	1.74E-07	7.97E-04	1.74E-07	7.97E-04	0.00E+00
3b	Large Isolation Failures (liner breach)	4.57E+04	4.36E-08	1.99E-03	4.38E-08	2.00E-03	7.73E-06
4	Small Isolation Failures (Failure to seal -Type B)	N/A	N/A	N/A	N/A	N/A	N/A
5	Small Isolation Failures (Failure to seal-Type C)	N/A	N/A	N/A	N/A	N/A	N/A
6	Other Isolation Failures (e.g., dependent failures)	N/A	N/A	N/A	N/A	N/A	N/A
7	Failures Induced by Phenomena (Early and Late)	3.02E+05	8.61E-06	2.60E+00	8.61E-06	2.60E+00	0.00E+00
8	Bypass (Interfacing System LOCA)	4.95E+05	1.00E-07	4.95E-02	1.00E-07	4.95E-02	0.00E+00
CDF	All CET end states	N/A	1.91E-05	2.67E+00	1.91E-05	2.67E+00	7.65E-06

Table 5-5: Farley Unit 1 Annual Dose as a Function of Accident Class; Characteristic of Conditions for ILRT Required 3/10 Years							
Accident Classes (Cnmt Release Type)	Description	Person-Rem (50 miles)	EPRI Methodology		EPRI Methodology Plus Corrosion		Change Due to Corrosion Person-Rem/yr$^{(1)}$
			Frequency (per Rx-yr)	Person-Rem/yr (50 miles)	Frequency (per Rx-yr)	Person- Rem/yr (50 miles)	

Notes:

1. Only release Classes 1 and 3b are affected by the corrosion analysis.
2. Characterized as 1La release magnitude consistent with the derivation of the ILRT non-detection failure probability for ILRTs. Release Classes 3a and 3b include failures of containment to meet the Technical Specification leak rate.

Table 5-6: Farley Unit 2 Annual Dose as a Function of Accident Class; Characteristic of Conditions for ILRT Required 3/10 Years							
Accident Classes (Cnmt Release Type)	**Description**	**Person-Rem (50 miles)**	**EPRI Methodology**		**EPRI Methodology Plus Corrosion**		**Change Due to Corrosion Person-Rem/yr(1)**
			Frequency (per Rx-yr)	**Person-Rem/yr (50 miles)**	**Frequency (per Rx-yr)**	**Person- Rem/yr (50 miles)**	
1	No Containment Failure (2)	4.57E+02	1.07E-05	4.88E-03	1.07E-05	4.88E-03	-7.29E-08
2	Large Isolation Failures (Failure to Close)	3.94E+05	3.27E-08	1.29E-02	3.27E-08	1.29E-02	0.00E+00
3a	Small Isolation Failures (liner breach)	4.57E+03	1.60E-07	7.30E-04	1.60E-07	7.30E-04	0.00E+00
3b	Large Isolation Failures (liner breach)	4.57E+04	4.00E-08	1.83E-03	4.01E-08	1.83E-03	7.29E-06
4	Small Isolation Failures (Failure to seal -Type B)	N/A	N/A	N/A	N/A	N/A	N/A
5	Small Isolation Failures (Failure to seal-Type C)	N/A	N/A	N/A	N/A	N/A	N/A
6	Other Isolation Failures (e.g., dependent failures)	N/A	N/A	N/A	N/A	N/A	N/A
7	Failures Induced by Phenomena (Early and Late)	3.02E+05	6.48E-06	1.96E+00	6.48E-06	1.96E+00	0.00E+00

Table 5-6: Farley Unit 2 Annual Dose as a Function of Accident Class; Characteristic of Conditions for ILRT Required 3/10 Years							
Accident Classes (Cnmt Release Type)	**Description**	**Person-Rem (50 miles)**	**EPRI Methodology**		**EPRI Methodology Plus Corrosion**		**Change Due to Corrosion Person-Rem/yr(1)**
			Frequency (per Rx-yr)	**Person-Rem/yr (50 miles)**	**Frequency (per Rx-yr)**	**Person- Rem/yr (50 miles)**	
8	Bypass (Interfacing System LOCA)	4.95E+05	9.60E-08	4.75E-02	9.60E-08	4.75E-02	0.00E+00
CDF	All CET end states	N/A	1.75E-05	2.03E+00	1.75E-05	2.03E+00	7.22E-06

Notes:

(1) Only release Classes 1 and 3b are affected by the corrosion analysis.

(2) Characterized as 1La release magnitude consistent with the derivation of the ILRT non-detection failure probability for ILRTs. Release classes 3a and 3b include failures of containment to meet the Technical Specification leak rate.

5.3 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 ten year value to fifteen years. To do this, an evaluation must first be made of the risk associated with the ten year interval since the base case applies to a three year interval (i.e., a simplified representation of a three in ten interval).

5.3.1 Risk Impact Due to 10-year Test Interval

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 3b sequences is directly impacted. As it is assumed that the new Class 3 end states arise from previously intact containment states, the intact state frequency is reduced accordingly. The risk contribution is changed based on the NEI guidance as described in Section 4.3 by a factor of 3.33 compared to the base case values. The results of the calculation for a ten year interval are presented in Table 5-7.

5.3.2 Risk Impact Due to 15-Year Test Interval

The risk contribution for a fifteen year interval is calculated in a manner similar to the ten 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 5.0 compared to the three year interval value, as described in Section 4.3. The results for this calculation are presented in Table 5-9 for Unit 1 and in Table 5-10 for Unit 2. (Note that the values for "Change due to corrosion - person-rem/yr" for Class 1 are negative, due to the removal of Class 3a and 3b frequencies from Class 1.)

Table 5-7: Farley Unit 1 Annual Dose as a Function of Accident Class; Characteristic of Conditions for ILRT Required 1/10 Years							
Accident Classes (Cnmt Release Type)	**Description**	**Person-Rem (50 miles)**	**EPRI Methodology**		**EPRI Methodology Plus Corrosion**		**Change Due to Corrosion Person-Rem/yr(1)**
			Frequency (per Rx-yr)	**Person-Rem/yr (50 miles)**	**Frequency (per Rx-yr)**	**Person-Rem/yr (50 miles)**	
1	No Containment Failure (2)	4.57E+02	9.63E-06	4.40E-03	9.63E-06	4.40E-03	-2.57E-07
2	Large Isolation Failures (Failure to Close)	3.94E+05	3.52E-08	1.39E-02	3.52E-08	1.39E-02	0.00E+00
3a	Small Isolation Failures (liner breach)	4.57E+03	5.81E-07	2.65E-03	5.81E-07	2.65E-03	0.00E+00
3b	Large Isolation Failures (liner breach)	4.57E+04	1.45E-07	6.64E-03	1.46E-07	6.66E-03	2.57E-05
4	Small Isolation Failures(Failure to seal-Type B)	N/A	N/A	N/A	N/A	N/A	N/A
5	Small Isolation Failures (Failure to seal-Type C)	N/A	N/A	N/A	N/A	N/A	N/A
6	Other Isolation Failures (e.g., dependent failures)	N/A	N/A	N/A	N/A	N/A	N/A
7	Failures Induced by Phenomena (Early and Late)	3.02E+05	8.61E-06	2.60E+00	8.61E-06	2.60E+00	0.00E+00
8	Bypass (Interfacing System LOCA)	4.95E+05	1.00E-07	4.95E-02	1.00E-07	4.95E-02	0.00E+00

Table 5-7: Farley Unit 1 Annual Dose as a Function of Accident Class; Characteristic of Conditions for ILRT Required 1/10 Years							
Accident Classes (Cnmt Release Type)	Description	Person-Rem (50 miles)	EPRI Methodology		EPRI Methodology Plus Corrosion		Change Due to Corrosion Person-Rem/yr(1)
			Frequency (per Rx-yr)	Person-Rem/yr (50 miles)	Frequency (per Rx-yr)	Person-Rem/yr (50 miles)	
CDF	All CET end states	N/A	1.91E-05	2.68E+00	1.91E-05	2.68E+00	2.55E-05

Notes:

1. Only release Classes 1 and 3b are affected by the corrosion analysis.
2. Characterized as 1La release magnitude consistent with the derivation of the ILRT non-detection failure probability for ILRTs. Release classes 3a and 3b include failures of containment to meet the Technical Specification leak rate.

Table 5-8: Farley Unit 2 Annual Dose as a Function of Accident Class; Characteristic of Conditions for ILRT Required 1/10 Years							
Accident Classes (Cnmt Release Type)	Description	Person-Rem (50 miles)	EPRI Methodology		EPRI Methodology Plus Corrosion		Change Due to Corrosion Person-Rem/yr(1)
			Frequency (per Rx-yr)	Person-Rem/yr (50 miles)	Frequency (per Rx-yr)	Person-Rem/yr (50 miles)	
1	No Containment Failure (2)	4.57E+02	1.02E-05	4.67E-03	1.02E-05	4.67E-03	-2.43E-07
2	Large Isolation Failures (Failure to Close)	3.94E+05	3.27E-08	1.29E-02	3.27E-08	1.29E-02	0.00E+00
3a	Small Isolation Failures (liner breach)	4.57E+03	5.32E-07	2.43E-03	5.32E-07	2.43E-03	0.00E+00
3b	Large Isolation Failures (liner breach)	4.57E+04	1.33E-07	6.08E-03	1.34E-07	6.10E-03	2.43E-05
4	Small Isolation Failures(Failure to seal-Type B)	N/A	N/A	N/A	N/A	N/A	N/A
5	Small Isolation Failures (Failure to seal-Type C)	N/A	N/A	N/A	N/A	N/A	N/A
6	Other Isolation Failures (e.g., dependent failures)	N/A	N/A	N/A	N/A	N/A	N/A
7	Failures Induced by Phenomena (Early and Late)	3.02E+05	6.48E-06	1.96E+00	6.48E-06	1.96E+00	0.00E+00
8	Bypass (Interfacing System LOCA)	4.95E+05	9.60E-08	4.75E-02	9.60E-08	4.75E-02	0.00E+00

Table 5-8: Farley Unit 2 Annual Dose as a Function of Accident Class; Characteristic of Conditions for ILRT Required 1/10 Years							
Accident Classes (Cnmt Release Type)	Description	Person-Rem (50 miles)	EPRI Methodology		EPRI Methodology Plus Corrosion		Change Due to Corrosion Person-Rem/yr(1)
			Frequency (per Rx-yr)	Person-Rem/yr (50 miles)	Frequency (per Rx-yr)	Person-Rem/yr (50 miles)	
CDF	All CET end states	N/A	1.75E-05	2.03E+00	1.75E-05	2.03E+00	2.40E-05

Notes:

(1) Only release Classes 1 and 3b are affected by the corrosion analysis.

(2) Characterized as 1La release magnitude consistent with the derivation of the ILRT non-detection failure probability for ILRTs. Release classes 3a and 3b include failures of containment to meet the Technical Specification leak rate.

Table 5-9: Farley Unit 1 Annual Dose as a Function of Accident Class; Characteristic of Conditions for ILRT Required 1/15 Years							
Accident Classes (Cnmt Release Type)	Description	Person-Rem (50 miles)	EPRI Methodology		EPRI Methodology Plus Corrosion		Change Due to Corrosion Person-Rem/yr(1)
			Frequency (per Rx-yr)	Person-Rem/yr (50 miles)	Frequency (per Rx-yr)	Person-Rem/yr (50 miles)	
1	No Containment Failure (2)	4.57E+02	9.26E-06	4.23E-03	9.26E-06	4.23E-03	-3.86E-07
2	Large Isolation Failures (Failure to Close)	3.94E+05	3.52E-08	1.39E-02	3.52E-08	1.39E-02	0.00E+00
3a	Small Isolation Failures (liner breach)	4.57E+03	8.72E-07	3.99E-03	8.72E-07	3.99E-03	0.00E+00
3b	Large Isolation Failures (liner breach)	4.57E+04	2.18E-07	9.97E-03	2.19E-07	1.00E-02	3.86E-05
4	Small Isolation Failures (Failure to seal-Type B)	N/A	N/A	N/A	N/A	N/A	N/A
5	Small Isolation Failures (Failure to seal-Type C)	N/A	N/A	N/A	N/A	N/A	N/A
6	Other Isolation Failures (e.g., dependent failures)	N/A	N/A	N/A	N/A	N/A	N/A
7	Failures Induced by Phenomena (Early and Late)	3.02E+05	8.61E-06	2.60E+00	8.61E-06	2.60E+00	0.00E+00

Table 5-9: Farley Unit 1 Annual Dose as a Function of Accident Class; Characteristic of Conditions for ILRT Required 1/15 Years

Accident Classes (Cnmt Release Type)	Description	Person-Rem (50 miles)	EPRI Methodology		EPRI Methodology Plus Corrosion		Change Due to Corrosion Person-Rem/yr(1)
			Frequency (per Rx-yr)	Person-Rem/yr (50 miles)	Frequency (per Rx-yr)	Person-Rem/yr (50 miles)	
8	Bypass (Interfacing System LOCA)	4.95E+05	1.00E-07	4.95E-02	1.00E-07	4.95E-02	0.00E+00
CDF	All CET end states	N/A	1.91E-05	2.68E+00	1.91E-05	2.68E+00	3.82E-05

Notes:

(1) Only release Classes 1 and 3b are affected by the corrosion analysis.

(2) Characterized as 1La release magnitude consistent with the derivation of the ILRT non-detection failure probability for ILRTs. Release Classes 3a and 3b include failures of containment to meet the Technical Specification leak rate.

Table 5-10: Farley Unit 2 Annual Dose as a Function of Accident Class; Characteristic of Conditions for ILRT Required 1/15 Years

Accident Classes (Cnmt Release Type)	Description	Person-Rem (50 miles)	EPRI Methodology		EPRI Methodology Plus Corrosion		Change Due to Corrosion Person-Rem/yr(1)
			Frequency (per Rx-yr)	Person-Rem/yr (50 miles)	Frequency (per Rx-yr)	Person-Rem/yr (50 miles)	
1	No Containment Failure (2)	4.57E+02	9.89E-06	4.52E-03	9.89E-06	4.52E-03	-3.64E-07
2	Large Isolation Failures (Failure to Close)	3.94E+05	3.27E-08	1.29E-02	3.27E-08	1.29E-02	0.00E+00
3a	Small Isolation Failures (liner breach)	4.57E+03	7.99E-07	3.65E-03	7.99E-07	3.65E-03	0.00E+00
3b	Large Isolation Failures (liner breach)	4.57E+04	2.00E-07	9.13E-03	2.01E-07	9.16E-03	3.64E-05
4	Small Isolation Failures (Failure to seal-Type B)	N/A	N/A	N/A	N/A	N/A	N/A
5	Small Isolation Failures (Failure to seal-Type C)	N/A	N/A	N/A	N/A	N/A	N/A
6	Other Isolation Failures (e.g., dependent failures)	N/A	N/A	N/A	N/A	N/A	N/A
7	Failures Induced by Phenomena (Early and Late)	3.02E+05	6.48E-06	1.96E+00	6.48E-06	1.96E+00	0.00E+00

Table 5-10: Farley Unit 2 Annual Dose as a Function of Accident Class; Characteristic of Conditions for ILRT Required 1/15 Years

Accident Classes (Cnmt Release Type)	Description	Person-Rem (50 miles)	EPRI Methodology		EPRI Methodology Plus Corrosion		Change Due to Corrosion Person-Rem/yr(1)
			Frequency (per Rx-yr)	Person-Rem/yr (50 miles)	Frequency (per Rx-yr)	Person-Rem/yr (50 miles)	
8	Bypass (Interfacing System LOCA)	4.95E+05	9.60E-08	4.75E-02	9.60E-08	4.75E-02	0.00E+00
CDF	All CET end states	N/A	1.75E-05	2.04E+00	1.75E-05	2.04E+00	3.61E-05

Notes:

(1) Only release Classes 1 and 3b are affected by the corrosion analysis.

(2) Characterized as 1La release magnitude consistent with the derivation of the ILRT non-detection failure probability for ILRTs. Release Classes 3a and 3b include failures of containment to meet the Technical Specification leak rate.

5.4 Step 4 - Determine the Change in Risk in Terms of Large Early Release Frequency (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 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 core damage frequency (CDF) below 10^{-6}/yr and increases in LERF below 10^{-7}/yr, and small changes in LERF as below 10^{-6}/yr. Because the ILRT does not impact CDF, the relevant metric is LERF.

For Farley Unit 1 and Unit 2, 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).

For Farley Unit 1, the baseline LERF based on a test frequency of three times in ten years is 4.38E-08/yr. Based on a ten year test interval from Table 5-11, the Class 3b frequency (conservatively including corrosion) is 1.46E-07/yr; and, based on a fifteen year test interval from Table 5-11, it is 2.19E-07/yr. Thus, the increase in the overall probability of LERF due to Class 3b sequences that is due to increasing the ILRT test interval from three to fifteen years is 1.75E-07/yr as shown in Table 5-11. Similarly, the increase due to increasing the interval from ten to fifteen years is 7.31E-08/yr as shown in Table 5-11.

For Farley Unit 2, the baseline LERF based on a test frequency of three times in ten years is 4.01E-08/yr. Based on a ten year test interval from Table 5-12, the Class 3b frequency (conservatively including corrosion) is 1.34E-07/yr; and, based on a fifteen year test interval from Table 5-12, it is 2.01E-07/yr. Thus, the increase in the overall probability of LERF due to Class 3b sequences that is due to increasing the ILRT test interval from three to fifteen years is 1.60E-07/yr as shown in Table 5-12. Similarly, the increase due to increasing the interval from ten to fifteen years is 6.70E-08/yr as shown in Table 5-12.

As can be seen, even with the conservatisms included in the evaluation (per the EPRI methodology), the estimated change in LERF for Farley Unit 1 and Unit 2 is below the threshold criteria for a very small change when comparing both the fifteen year results to the current ten year requirement, and below the threshold criteria for small change when the fifteen year results compared to the original three year requirement. (According to RG 1.1.74, when the calculated increase in LERF is in the range of 1.0E-7 per reactor-year to 1.0E-6 per reactor-year, the applications will be considered acceptable only if the total plant LERF is less than 1.0E-5 per reactor-year.) See Table 5-11 and Table 5-12 for more information.

5.5 Step 5 – Determine the Impact on the Conditional Containment Failure Probability (CCFP)

Another parameter that the NRC guidance in RG 1.174 states can provide input into the decision-making process is the change in the conditional containment failure probability (CCFP). The change in CCFP is indicative of the effect of the ILRT on all radionuclide releases, not just LERF. The CCFP can be calculated from the results of this analysis. One of the difficult aspects of this calculation is providing a definition of the "failed containment." In this assessment, the CCFP is defined such that containment failure includes all radionuclide release end states other than the intact state. The conditional part of the definition is conditional given a severe accident (i.e., core damage).

The change in CCFP can be calculated by using the method specified in the EPRI Report No. 1009325, Revision 2-A. The NRC has previously accepted similar calculations (Reference 9) as the basis for showing that the proposed change is consistent with the defense-in-depth philosophy. The list below shows the CCFP values that result from the assessment for the various testing intervals including corrosion effects.

$CCFP = [1 - (\text{Class 1 frequency} + \text{Class 3a frequency}) / CDF] * 100\%$

Unit 1

$CCFP_{3\ \text{Unit 1}} = [1 - (1.01E\text{-}05/yr + 1.74E\text{-}07/yr) / 1.91E\text{-}05/yr] * 100\% = 46.02\%$

$CCFP_{3\ \text{Unit 1}} = 46.02\%$

$CCFP_{10\ \text{Unit 1}} = [1 - (9.63E\text{-}06/yr + 5.81E\text{-}07/yr) / 1.91E\text{-}05/yr] * 100\% = 46.56\%$

$CCFP_{10\ \text{Unit 1}} = 46.56\%$

$CCFP_{15\ \text{Unit 1}} = [1 - (9.26E\text{-}06/yr + 8.72E\text{-}07/yr) / 1.91E\text{-}05/yr] * 100\% = 46.94\%$

$CCFP_{15\ \text{Unit 1}} = 46.94\%$

$\Delta CCFP_{\text{Unit 1}} = CCFP_{15} - CCFP_{3} = 0.92\%$

$\Delta CCFP_{\text{Unit 1}} = CCFP_{15} - CCFP_{10} = 0.38\%$

$\Delta CCFP_{\text{Unit 1}} = CCFP_{10} - CCFP_{3} = 0.53\%$

Unit 2

$CCFP_{3\ \text{Unit 2}} = [1 - (1.07E\text{-}05/yr + 1.60E\text{-}07/yr) / 1.75E\text{-}05/yr] * 100\% = 38.02\%$

$CCFP_{3\ \text{Unit 2}} = 38.02\%$

$CCFP_{10\ \text{Unit 2}} = [1 - (1.02E\text{-}05/yr + 5.32E\text{-}07/yr) / 1.75E\text{-}05/yr] * 100\% = 38.55\%$

$CCFP_{10\ \text{Unit 2}} = 38.55\%$

$CCFP_{15\ Unit\ 2} = [1 - (9.89E\text{-}06/yr + 7.99E\text{-}07/yr) / 1.75E\text{-}05/yr] * 100\% = 38.93\%$

$CCFP_{15\ Unit\ 2} = 38.93\%$

$\Delta CCFP_{Unit\ 2} = CCFP_{15} - CCFP_{3} = 0.92\%$

$\Delta CCFP_{Unit\ 2} = CCFP_{15} - CCFP_{10} = 0.38\%$

$\Delta CCFP_{Unit\ 2} = CCFP_{10} - CCFP_{3} = 0.53\%$

The change in CCFP of approximately 0.92% by extending the test interval to fifteen years from the original three in ten year for Farley Unit 1 and Unit 2 requirement is judged to be very small.

5.6 Summary of Results

The results from this ILRT extension risk assessment for Farley are summarized in Table 5-11 for Farley Unit 1 and Table 5-12 for Farley Unit 2.

Table 5-11: Farley Unit 1 ILRT Cases: Base, 3 to 10, and 3 to 15 Yr Extensions (Including Age Adjusted Steel Liner Corrosion Likelihood)

EPRI Class	DOSE Per-Rem	Base Case 3 in 10 Years		Extend to 1 in 10 Years		Extend to 1 in 15 Years	
		CDF/Yr	Per-Rem/Yr	CDF/Yr	Per-Rem/Yr	CDF/Yr	Per-Rem/Yr
1	4.57E+02	1.01E-05	4.63E-03	9.63E-06	4.40E-03	9.26E-06	4.23E-03
2	3.94E+05	3.52E-08	1.39E-02	3.52E-08	1.39E-02	3.52E-08	1.39E-02
3a	4.57E+03	1.74E-07	7.97E-04	5.81E-07	2.65E-03	8.72E-07	3.99E-03
3b	4.57E+04	4.38E-08	2.00E-03	1.46E-07	6.66E-03	2.19E-07	1.00E-02
7	3.02E+05	8.61E-06	2.60E+00	8.61E-06	2.60E+00	8.61E-06	2.60E+00
8	4.95E+05	1.00E-07	4.95E-02	1.00E-07	4.95E-02	1.00E-07	4.95E-02
Total	N/A	1.91E-05	2.67E+00	1.91E-05	2.68E+00	1.91E-05	2.68E+00
ILRT Dose Rate from 3a and 3b Per-Rem/Yr		2.80E-03		9.32E-03		1.40E-02	
Delta Total Dose Rate[1]	From 3 yr	N/A		6.29E-03		1.08E-02	
	From 10 yr	N/A		N/A		4.51E-03	
% change in dose rate from base	From 3 yr	N/A		0.24%		0.40%	
	From 10 yr	N/A		N/A		0.17%	
3b Frequency (LERF)/Yr		4.38E-08		1.46E-07		2.19E-07	
Delta LERF	From 3 yr	N/A		1.02E-07		1.75E-07	
	From 10 yr	N/A		N/A		7.31E-08	
CCFP %		46.02%		46.56%		46.94%	
Delta CCFP %	From 3 yr	N/A		0.53%		0.92%	
	From 10 yr	N/A		N/A		0.38%	

Notes:

1. The overall difference in total dose rate is less than the difference of only the 3a and 3b categories between two testing intervals. This is because the overall total dose rate includes contributions from other categories that do not change as a function of time, e.g., the EPRI Class 2 and 8 categories, and also due to the fact that the Class 1 person-rem/yr decreases when extending the ILRT frequency.

Table 5-12: Farley Unit 2 ILRT Cases: Base, 3 to 10, and 3 to 15 Yr Extensions (Including Age Adjusted Steel Liner Corrosion Likelihood)

EPRI Class	DOSE Per-Rem	Base Case 3 in 10 Years		Extend to 1 in 10 Years		Extend to 1 in 15 Years	
		CDF/Yr	Per-Rem/Yr	CDF/Yr	Per-Rem/Yr	CDF/Yr	Per-Rem/Yr
1	4.57E+02	1.07E-05	4.88E-03	1.02E-05	4.67E-03	9.89E-06	4.52E-03
2	3.94E+05	3.27E-08	1.29E-02	3.27E-08	1.29E-02	3.27E-08	1.29E-02
3a	4.57E+03	1.60E-07	7.30E-04	5.32E-07	2.43E-03	7.99E-07	3.65E-03
3b	4.57E+04	4.01E-08	1.83E-03	1.34E-07	6.10E-03	2.01E-07	9.16E-03
7	3.02E+05	6.48E-06	1.96E+00	6.48E-06	1.96E+00	6.48E-06	1.96E+00
8	4.95E+05	9.60E-08	4.75E-02	9.60E-08	4.75E-02	9.60E-08	4.75E-02
Total	N/A	1.75E-05	2.03E+00	1.75E-05	2.03E+00	1.75E-05	2.04E+00

		Base Case 3 in 10 Years	Extend to 1 in 10 Years	Extend to 1 in 15 Years
ILRT Dose Rate from 3a and 3b Per-Rem/Yr		2.56E-03	8.54E-03	1.28E-02
Delta Total Dose Rate[1]	From 3 yr	N/A	5.76E-03	9.89E-03
	From 10 yr	N/A	N/A	4.13E-03
% change in dose rate from base	From 3 yr	N/A	0.28%	0.49%
	From 10 yr	N/A	N/A	0.20%
3b Frequency (LERF)/Yr		4.01E-08	1.34E-07	2.01E-07
Delta LERF	From 3 yr	N/A	9.35E-08	1.60E-07
	From 10 yr	N/A	N/A	6.70E-08
CCFP %		38.02%	38.55%	38.93%
Delta CCFP %	From 3 yr	N/A	0.53%	0.92%
	From 10 yr	N/A	N/A	0.38%

Notes:

1. The overall difference in total dose rate is less than the difference of only the 3a and 3b categories between two testing intervals. This is because the overall total dose rate includes contributions from other categories that do not change as a function of time, e.g., the EPRI Class 2 and 8 categories, and also due to the fact that the Class 1 person-rem/yr decreases when extending the ILRT frequency.

6 Sensitivities

6.1 Sensitivity to Corrosion Impact Assumptions

The Farley Unit 1 and Unit 2 results in Table 5-5 through Table 5-10 show that including corrosion effects calculated using the assumptions described in Section 4.4 does not significantly affect the results of the ILRT extension risk assessment.

Sensitivity cases were developed to gain an understanding of the sensitivity of the results to the key parameters in the corrosion risk analysis. The time for the flaw likelihood to double was adjusted from every five years to every two and every ten years. The failure probabilities for the upper containment and the basemat were increased and decreased by an order of magnitude. The total detection failure likelihood was adjusted from 10% to 15% and 5%. The results are presented in Table 6-1. In every case the impact from including the corrosion effects is very minimal. Even the upper bound estimates with very conservative assumptions for all of the key parameters yield increases in LERF due to corrosion of only 1.69E-11/yr for Unit 1 and 1.59E-11 for Unit 2. The results indicate that even with very conservative assumptions, the conclusions from the base analysis would not change.

Table 6-1: Steel Plate Corrosion Sensitivity Cases[3]						
Age (Step 3 in the corrosion analysis)	Containment Breach (Step 4 in the corrosion analysis)	Visual Inspection & Non-Visual Flaws (Step 5 in the corrosion analysis)	Unit 1 Increase in Class 3b Frequency (LERF) for ILRT Extension 3 to 15 Years (per Rx-yr)		Unit 2 Increase in Class 3b Frequency (LERF) for ILRT Extension 3 to 15 Years (per Rx-yr)	
			Total Increase	Increase Due to Corrosion	Total Increase	Increase Due to Corrosion
Base Case Doubles every 5 yrs.	Base Case (1% Upper Containment, 0.1% Basemat)	Base Case (10% Upper Containment, 100% Basemat)	1.03E-07	6.76E-10	1.03E-07	6.38E-10
Doubles every 2 yrs.	Base	Base	1.03E-07	1.20E-09	1.03E-07	1.14E-09
Doubles every 10 yrs.	Base	Base	1.02E-07	1.95E-10	1.02E-07	1.84E-10
Base	Base	15%	1.03E-07	9.46E-10	1.03E-07	8.93E-10
Base	Base	5%	1.02E-07	4.07E-10	1.02E-07	3.84E-10
Base	10% Upper Containment, 1% Basemat	Base	1.09E-07	6.76E-09	1.08E-07	6.38E-09
Base	0.1% Upper Containment, 0.01% Basemat	Base	1.02E-07	6.76E-11	1.02E-07	6.38E-11
Lower Bound						
Doubles every 10 yrs.	0.1% Upper Containment, 0.01% Basemat	5% Upper Containment, 1% Basemat	1.02E-07	1.17E-14	1.02E-07	1.10E-14
Upper Bound						
Doubles every 2 yrs.	10% Upper Containment, 1% Basemat	15% Upper Containment, 100% Basemat	1.02E-07	1.69E-11	1.02E-07	1.59E-11

[3] The values in this table come directly from Table 4.4-1 in Appendix H of Reference 21.

6.2 Sensitivity to Class 3b Contribution to LERF

For Unit 1, the Class 3b frequency for the base case of a three in ten year ILRT interval including corrosion is 4.38E-08/yr (Table 5-5). Extending the interval to one in ten years results in a frequency of 1.46E-07/yr (Table 5-7). Extending it to one in fifteen years results in a frequency of 2.19E-07/yr (Table 5-9), which is an increase of 1.75E-07/yr from three in ten years to once in fifteen years.

For Unit 2, the Class 3b frequency for the base case of a three in ten year ILRT interval including corrosion is 4.01E-08/yr (Table 5-6). Extending the interval to one in ten years results in a frequency of 1.34E-07/yr (Table 5-8). Extending it to one in fifteen years results in a frequency of 2.01E-07/yr (Table 5-10), which is an increase of 1.60E-07/yr from three in ten years to once in fifteen years.

If 100% of the Class 3b sequences are assumed to have potential releases large enough for LERF, then the increase in LERF due to extending the interval from three in ten to one in fifteen is above the RG 1.174 threshold for very small changes in LERF of 1.00E-07/yr.

6.3 Potential Impact from External Events Contribution

The latest information related to external events for Farley Unit 1 and Unit 2 is from the plants' license renewal (Reference 26) and the Farley Fire PRA (Reference 27).

Table 6-2 lists the Farley CDF and LERF values for each internal and external event type that are used to determine the potential impact from the External Events contribution. The values for the internal events PRA come from Section 4.2.1 above. The values for the Fire PRA come from Table 3-1 of Reference 27. The Farley Fire PRA models credit pending modifications for NFPA 805 that will be fully implemented by the end of 2017. The earliest this ILRT extension will be implemented is in 2018.

The value for Seismic and Other External Risk comes from Table 6-1 – Summary of Total Plant Risk, page E-28 of Reference 28.

Table 6-2: Farley Internal and External Events Summary

Event Type	Farley Unit 1		Farley Unit 2	
	CDF (per/year)	LERF (per/year)	CDF (per/year)	LERF (per/year)
Internal Events	1.91E-05	1.35E-07	1.75E-05	1.33E-07
Fire Events	6.61E-05	4.83E-06	7.33E-05	7.11E-06
Seismic	1.08E-05	1.26E-07	1.08E-05	1.62E-07
Other External Risk	Screened out	Screened out	Screened out	Screened out
Total	**9.60E-05**	**5.09E-06**	**1.02E-04**	**7.41E-06**

Combining the External Events CDF values and the Internal Events CDF yields a CDF estimate of 9.60E-05/yr (Unit 1) and 1.02E-04/yr (Unit 2). LERF estimates including External Events are 5.09E-06/yr (Unit 1) and 7.41E-06/yr (Unit 2). It is noted that the value for Total Internal and

External events CDF slightly exceeds a value of 1.0E-04. This value is expected to fall below 1.0E-04 when the Farley Internal Events PRAs for Unit 1 and Unit 2 credit the Generation III RCP shutdown seals which are already installed. Crediting the Generation III RCP seals is expected to reduce Internal Events CDF to the mid 1E-06/yr range on both units. The PRA model update with the Generation III RCP seals is expected to be released in 2016.

The change in LERF from extending the Type A test interval can be conservatively estimated using the total CDF values to determine the external event contribution. These CDF values were specifically used to determine the Class 3b frequency (neglecting corrosion[4]) based on the external events contribution. The factors for determining the increase in the non-detection probability of a leak described in Section 4.3 were applied to the Class 3b base value frequencies to determine the 3b frequencies for the once per ten year test and once per fifteen year test for each unit.

Class 3b Frequency (three per ten year test) = 0.0023 * (CDF - LERF)

Class 3b Frequency (Unit 1) = 0.0023 * (9.60E-05/yr – 5.09E-06/yr) = 2.09E-07/yr

Class 3b Frequency (Unit 1) (once per ten year test) = 3.33 * 2.09E-07/yr = 6.97E-07/yr

Class 3b Frequency (Unit 1) (once per fifteen year test) = 5.00 * 2.09E-07/yr = 1.05E-06/yr

Class 3b Frequency (Unit 2) = 0.0023 * (1.02E-04/yr – 7.41E-06/yr) = 2.17E-07/yr

Class 3b Frequency (Unit 2) (once per ten year test) = 3.33 * 2.17E-07/yr = 7.22E-07/yr

Class 3b Frequency (Unit 2) (once per fifteen year test) = 5.00 * 2.17E-07/yr = 1.08E-06/yr

Table 6-4 shows the results of these calculations. Note that in the above calculation Class 3b releases are considered to arise from a change in state of prior non-LERF states to a LERF (Class 3b) state.

Table 6-3: Farley Estimated Total LERF Including External Events Impact

Case	3b Frequency (3 per 10 year test)	3b Frequency (1 per 10 year test)	3b Frequency (1 per 15 year test)	LERF Increase (3 per 10 to 1 per 15)
Unit 1 Internal Events Contribution (From Base Case Table 5-11)	4.38E-08	1.46E-07	2.19E-07	1.75E-07
Unit 1 Total Contribution including External Events	2.09E-07	6.97E-07	1.05E-06	8.37E-07

[4] Corrosion effects are not explicitly considered in the sensitivity assessment as the impact is negligible.

Table 6-3: Farley Estimated Total LERF Including External Events Impact				
Case	**3b Frequency (3 per 10 year test)**	**3b Frequency (1 per 10 year test)**	**3b Frequency (1 per 15 year test)**	**LERF Increase (3 per 10 to 1 per 15)**
Unit 2 Internal Events Contribution (From Base Case Table 5-12)	4.01E-08	1.34E-07	2.01E-07	1.60E-07
Unit 2 Total Contribution including External Events	2.17E-07	7.22E-07	1.08E-06	8.67E-07

Using the above approach results in a total LERF (Class 3b) value of 1.05E-06/yr for a permanent once per 15 year ILRT program for Unit 1 and 1.08E-06/yr for Unit 2. These frequencies remain below the Regulatory Guide 1.174 criteria of 1.00E-05/yr following the ILRT extension. Furthermore, the increase in total LERF from the three per ten year test to the once per fifteen year test is 8.37E-07/yr for Unit 1 and 8.67E-07/yr for Unit 2, both of which are within the range of the Regulatory Guide 1.174 criteria of 1.00E-07/yr to 1.00E-06/yr for a small change in risk.

7 Conclusions

Based on the results from Section 5 and the sensitivity calculations presented in Section 0, the following conclusions regarding the assessment of the plant risk are associated with permanently extending the Type A ILRT test frequency to once in fifteen years:

- Regulatory Guide 1.174, (Reference 4) provides acceptance criteria for increase in CDF and LERF resulting from a risk-informed application. Since the ILRT does not impact CDF, the relevant criterion for this application is LERF. When the calculated increase in LERF is "very small", which is taken as being less than 1.0E-7 per reactor-year, the change will be generally considered acceptable irrespective of the plant's LERF value. When the calculated increase in LERF is in the range of 1.0E-7 per reactor-year to 1.0E-6 per reactor-year, the applications will be considered acceptable only if the total plant LERF is less than 1.0E-5 per reactor-year. The increase in LERF based on the internal events PRA, resulting from a change in the Type A ILRT test interval from three in ten years to one in fifteen years, is conservatively estimated as 1.75E-07/yr for Unit 1 and 1.60E-07/yr for Unit 2, using the EPRI guidance as written. These estimated changes in LERF for Farley Unit 1 and Unit 2 while not "very small" are still determined to be within the acceptance guidelines of Reg. Guide 1.174, since the plants' LERF values from the internals events PRA are below 1.0E-5 per reactor-year.

- A sensitivity analysis was performed to evaluate the impact of the ILRT application on both internal and external events PRA results. Regulatory Guide 1.174 (Reference 4) states that applications that result in increases to LERF above 1.0E-6 per reactor-year would not normally be considered. Both these values are slightly over the RG 1.174 acceptance criteria value of 1.0E-6. However, as explained in Section 6.3, when the PRA

is revised later in 2016 taking credit for the Generation III RCP shutdown seals which are already installed, the plant CDF and LERF values are expected to be significantly lower and similarly the increase in LERF values attributable to ILRT will be considerably lower and below the 1.0E-6 threshold, thus meeting the RG 1.174 criteria.

- According to the Regulatory Guide 1.174 even though the proposed changes to ILRT do not change the CDF values, no changes would be permitted per this Regulatory Guide if the plant CDF exceeds 1.0E-4 per year. For the sensitivity case of the examination of the impact of external events, the calculated CDF, with the external events included, the CDF for Unit 2 is 1.02 E-4 which slightly higher than this value. However, as explained in Section 6.3, when the PRA is revised later in 2016 taking credit for the Generation III RCP shutdown seals which are already installed, the plant CDF are expected to be significantly below the 1.0E-4 per year threshold.

- The change in Type A test frequency to once per fifteen 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 PRA is 1.08E-02 person-rem/yr for Unit 1 and 9.89E-03 person-rem/yr for Unit 2. EPRI Report No. 1009325, Revision 2-A states that a very 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. This is consistent with the NRC Final Safety Evaluation for NEI 94-01 and EPRI Report No. 1009325 (Reference 24). Moreover, the risk impact when compared to other severe accident risks is negligible.

- The increase in the conditional containment failure probability from the three in ten year interval to a permanent one time in fifteen year interval is 0.92% for Unit 1 and 0.92% for Unit 2. EPRI Report No. 1009325, Revision 2-A states that increases in CCFP of ≤1.5 percentage points are very small. This is consistent with the NRC Final Safety Evaluation for NEI 94-01 and EPRI Report No. 1009325 (Reference 24). Therefore this increase is judged to be very small.

Therefore, permanently increasing the ILRT interval to fifteen years is considered to be a very small change to the Farley Unit 1 and Unit 2 risk profile.

7.1.1 Previous Assessments

The NRC in NUREG-1493 (Reference 6) has previously concluded that:

- Reducing the frequency of Type A tests (ILRTs) from three per ten years to one per twenty 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 and 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. Beyond

testing the performance of containment penetrations, ILRTs also test the integrity of the containment structure.

The findings for Farley Unit 1 and Unit 2 confirm these general findings on a plant specific basis considering the severe accidents evaluated for Farley Unit 1 and Unit 2, the Farley Unit 1 and Unit 2 containment failure modes, and the local population surrounding Farley Unit 1 and Unit 2.

8 References

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38. Letter from M. J. Ajluni (Southern Nuclear Company) to Document Control Desk (NRC), NL-12-1893, dated September 25, 2012, *Joseph M. Farley Nuclear Plant License Amendment Request to Adopt NFPA 805 Performance Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants*

39. U.S. Nuclear Regulatory Commission, Lettter to C. R. Pierce (Southern Nuclear Co.) dated March 10, 2015, "Joseph M. Farley Nuclear Plant, Units 1 and 2 – Issuance of Amendment Regarding transition to a Risk-Informed Performance-Based Fire Protection Program in

Accordance with 10 CFR 50.48(c) (TAC Nos. ME9741 and ME9742)," Enclosure 3, "Safety Evaluation by the Office of Nuclear Reactor Regulation," "Transition to a Risk-Informed, Performance-Based Fire Protection Program in Accordance with 10 CFR 50.48(c)." [ML 14308A048]

Appendix A

Farley Units 1 and 2 Permanent ILRT Interval Extension Risk Impact Assessment: PRA Capability

A.1 OVERVIEW

A Probabilistic Risk Assessment (PRA) analysis is utilized in the containment Type A Integrated Leak Rate Test (ILRT) risk assessment to support an extension of the Farley Unit 1 and Unit 2 test interval from ten year to fifteen years.

The guidance provided in Regulatory Guide 1.200 (Reference 33) (Section 4.2) indicates that the following items be addressed in documentation submitted to the NRC to demonstrate the technical adequacy of the PRA:

1. Identification of permanent plant changes (such as design or operational practices) that have an impact on the PRA but have not been incorporated in the PRA.
2. The parts of the PRA used to produce the results are performed consistently with the PRA Standard as endorsed by RG 1.200.
3. A summary of the risk assessment methodology used to assess the risk of the application, including how the PRA model was modified to appropriately model the risk impact of the application.
4. Identifications of key assumptions and approximations in the PRA relevant to the results used in the decision making process.
5. A discussion of the resolution of peer review or self-assessment findings and observations that are applicable to the parts of the PRA required for the application.
6. Identification of parts of the PRA used in the analysis that were assessed to have capability categories less than that required for the application.

The purpose of this Appendix is to address the requirements identified above.

A.2 TECHNICAL ADEQUACY OF THE PRA MODEL

The PRA model version used for the ILRT extension risk assessment is the Farley Units 1 and 2 Internal Events PRA Revision 9 Version 3 (Reference 34).

Revision 9 Version 3 of the Farley PRA model is the current model of record at the time of this evaluation for Farley Units 1 and 2 for internal event challenges. The PRA modeling is highly detailed, including a wide variety of initiating evens, modeled systems, operator actions, and common cause events. The PRA model quantification process used for the Farley PRA is based on the event tree / fault tree methodology, which is a well-known methodology in the industry.

The Farley PRA models are controlled in accordance with SNC procedure RIE-001, "Generation and Maintenance of Probabilistic Risk Assessment Models and Associated Updates," (Reference 35) and associated guidelines. This procedure defines the process for implementing regularly scheduled and interim PRA model updates, for tracking issues identified as potentially affecting the PRA models (e.g., due to changes in the plant, errors or limitations identified in the model, industry operating experience, etc.), and for controlling the model and associated computer files. To ensure that the current PRA model remains an accurate reflection of the as-built, as-operated plants, RIE-001 requires the following activities outlined in the procedure are routinely performed:

- Design changes and procedure changes are reviewed for their impact on the PRA model on an on-going basis.
- Reliability data, unavailability data, initiating events frequency data, human reliability data, and other such PRA inputs shall be reviewed approximately every two fuel cycles and updated as necessary to maintain the PRA consistent with the as-operated plant.

As indicated previously, RG-1.200 also requires that additional information be provided as part of the submittal to demonstrate the technical adequacy of the PRA model used for the risk assessment. Each of these items are addressed in the following sections.

A.2.1 Plant Changes Not Yet Incorporated into the PRA Model

As part of PRA model configuration control, SNC maintains a PRA model maintenance database that tracks all issues that have been identified that could impact the Farley PRA model. Per Reference 35 the significance of the pending items in the database is evaluated to determine the impact on model results. Each pending item is prioritized for future model updates according to its significance to model results.

A.2.2 Parts of the PRA Used

The ILRT risk assessment utilizes the overall Level 1 and Level 2 results from Reference 34, as noted in the main report of the ILRT risk assessment. Section 3.2.4.1 of the NRC final safety evaluation (Reference 37) of the EPRI ILRT risk assessment methodology documents that Capability Category I is appropriate since approximate values of Core Damage Frequency (CDF) and Large Early Release Frequency (LERF) and their distribution among release categories are sufficient for use in the EPRI methodology.

A.2.3 Risk Assessment Methodology Summary

The ILRT risk assessment methodology is based on EPRI TR-1018243 (Reference 21). The methodology as applied for Farley is fully described in the main report of the ILRT risk assessment.

A.2.4 PRA Key Assumptions and Approximations

For this application, the EPRI methodology involves a bounding approach to estimate the change in LERF for extending the ILRT interval. Rather than exercising the PRA model itself, the methodology involves the establishment of separate calculations that are linearly related to the plant CDF contribution that is not already LERF. The ILRT risk assessment methodology incorporates various assumptions and approximations identified in the main report of the ILRT risk assessment. Key EPRI methodology assumptions and approximations are addressed via sensitivity studies. Any assumptions and approximations utilized in the PRA are judged to have negligible impacts compared to those utilized in the EPRI methodology for the purposes of this application.

A.2.5 Assessment of PRA model Technical Adequacy

Several assessments of technical capability have been made for the Farley Units 1 and 2 Internal Events PRA models:

- An independent PRA peer review was conducted under the auspices of the Westinghouse Owners Group (WOG) in 2001, following the Industry PRA Peer Review process (Reference 31). This peer review included an assessment of the PRA model maintenance and update process.
- In 2005, a gap analysis was performed against the available version of the ASME PRA Standard (Reference 29) and Regulatory Guide 1.200, Revision 0 (Reference 30).

The Farley Unit 1 Probabilistic Risk Assessment (PRA) Peer Review was performed in March of 2010 at the Southern Nuclear offices in Birmingham, AL, using the NEI 05-04 process (Reference 31), the 2009 version of the ASME/ANS PRA Standard (Reference 32), and Regulatory Guide 1.200, Revision 2 (Reference 33). The purpose of this review was to provide a method or establishing the technical adequacy of the PRA for the spectrum of potential risk-informed plant licensing applications for which the PRA may be used.

The 2010 Farley Unit 1 PRA Peer Review was a full-scope review of the Technical Elements of the internal events (including internal flooding), at-power PRA. The PRA reviewed for this Peer Review was the Revision 9 Version 1 of the Farley Unit 1 PRA model.

A summary of the peer review is described in the following information.

- The ASME PRA Standard contains a total of 326 numbered supporting requirements in 14 technical elements and the configuration control element. Of the 326 SRs, eight were determined to be not applicable to the Farley Unit 1PRA.
- Among 318 applicable SRs, 92% of SRs met Capability Category II or higher as follows:

Capability Category Met	No. of SRs	% of total applicable SRs
CC I/II/III (or SR Met)	213	65%
CC I	9	3%
CC II	30	9%
CC III	12	4%
CC I/II	13	4%
CC II/III	24	7%
SR Not Met	17	5%
SR Not Applicable	8	3%
Total	**326**	**100%**

The 17 "SR Not Met" have been addressed and closed. Reference 36 discusses each of the peer review findings and its closure. Table 1 shows details of the 17 "SR Not Met" findings and resolutions after the peer review.

In addition to the Internal Events PRA models used for this ILRT Risk Assessment, Farley has Fire PRA models for Units 1 and 2 which were developed for Risk Informed applications including NFPA 805.

The Farley Fire PRA models underwent a RG 1.200, Revision 2, peer review against the ASME PRA Standard, conducted by the Pressurized Water Reactor Owner's Group (PWROG) in October 2011 in accordance with NEI 07-12. The peer review concluded that the methodologies used in development of the Farley Fire PRA models were appropriate and sufficient to satisfy ASME/ANS PRA Standard RA-Sa-2009. The results of the Fire PRA peer review were included in the license amendment request (LAR) submitted to NRC for approval to transition to NFPA 805 (Reference 38).

In addition to the PWROG peer review, the Farley Fire PRA was extensively reviewed by NRC as part of their review and audit of the Farley NFPA 805 LAR submittal. Following their review and approval of the license amendment, NRC issued a safety evaluation report (SER) (Reference 39) which noted that the disposition and closure of the Fire PRA peer review findings and observations (F&Os) are acceptable.

Based on the results of these reviews the Farley Fire PRA meets the requirements of the ASME PRA Standard and therefore is technically adequate and of sufficient quality for use in Risk Informed applications. Although not used in the quantitative ILRT Risk Assessment, the Fire PRA CDF and LERF values for Units 1 and 2 are shown in Table 6-2 which provides a summary of the contributions of the Farley Internal Events, Fire Events, Seismic, and other External Events models to the total CDF and LERF for each Unit.

Table 1: Resolution of the Farley PRA Peer Review F&Os Associated with the 17 Not Met SRs				
F&O#	**Review Element**	**Description**	**Resolution proposed by Peer Review**	**Resolution Status by SNC**
IE-A5-01	IE-A5 (SR CCI) met CCI	The system notebooks look at the impact of the identified initiators on that system. However, a system by system review might identify additional plant specific initiators, particularly associated with transformers, buses, etc.	Add a systematic review of the safety and non-safety systems that could cause a plant scram to verify that no additional initiators are needed	A systematic review of the Farley safety and non-safety systems was performed that resulted in the development of a Table C-1 "Farley Initiating Event Identification Analysis" which is documented as part of the Farley Initiating Event Notebook (RIE-NB-REV9-F-IE). This table lists each Farley system ordered by a system group identifier, system ID, system description, impact of system loss and treatment of system loss in Farley PRA. The "treatment of system loss" addressed specifically whether the loss of a system would result in an initiating event and how the initiating event was grouped. This finding is considered closed.
IE-A9-01	IE-A9 (SR CCI) met CCI	A plant-specific review of potential precursor events, such as intake structure clogging and others, has not been performed Farley Unit 1.	Review significant non-scram events at the plant to determine if any precursors exist	A search was performed using the Condition Reports database for significant non-scram events. A comparison of the results was made to Farley's initiating events list. No new initiating event precursors to plant trips were found. Added methodology and review results in Appendix A of the Initiating Events notebook (RIE-NB-REV9-F-IE). This finding is considered closed.

Table 1: Resolution of the Farley PRA Peer Review F&Os Associated with the 17 Not Met SRs				
F&O#	**Review Element**	**Description**	**Resolution proposed by Peer Review**	**Resolution Status by SNC**
IE-B1-01	IE-B3 (SR CCI) met CCI	Several cases were noted where grouping in the IE document is unclear or incorrect. Therefore, additional documentation is needed to verify that the event grouping is clear and can be easily traced to the plant impact.'	Include the impact of the initiator on the PSA systems in the model	Table C-1 "Farley Initiating Event Identification Analysis" was created and documented in the Farley Initiating Event Notebook (RIE-NB-REV9-F-IE). This table lists each Farley system ordered by a system group identifier, system ID, system description, impact of system loss and treatment of system loss in Farley PRA. The treatment of "system loss" addressed specifically whether the loss of a system would result in an initiating event and how the initiating event was grouped. This finding is considered closed.
IE-C5-01	IE-C5 (SR CC-I/II/III) not met	Farley Unit 1 did not weigh the initiating event frequencies by the fraction of time the plant is at power.	Modify the initiating event frequency to address plant availability	The adjustment has been made as part of the model quantification. Appendix B-2 of the Initiating Events notebook (RIE-NB-REV9-F-IE) contains the development of the annual average availability factor. This finding is considered closed.

Table 1: Resolution of the Farley PRA Peer Review F&Os Associated with the 17 Not Met SRs				
F&O#	**Review Element**	**Description**	**Resolution proposed by Peer Review**	**Resolution Status by SNC**
AS-C2-02	AS-C2 (SR CC-I/II/III) not met	The Farley Unit 1 AS notebook provides discussions of the examples indicated in the SR. Improve the level of documentation.	Add initiating events %LOSPF and %LOSPG to Table 2.6-1 Correct the descriptions of initiating events %LOSSACF and %LOSSACG in Table 2.6-4	The Accident Sequence notebook (RIE-NB-REV9-F-AS) was revised to correctly reference the loss of bus initiating events. The descriptions of the %LOSSACF and %LOSSACG events in Table 2.6-4 were not changed because they are correct. Instead, the descriptions for those events were corrected in Table 2.6-1 and events %LOSPF and %LOSPG were added to Table 2.6-1. Documentation was revised. This finding is considered closed.
SY-C1-01	SY-C1 (SR CC-I/II/III) not met	The system notebooks documentation on test and maintenance for several systems is incorrect and references old or incorrect documents.	Correct the System notebook's references for test and maintenance information	This is a documentation issue. The references (RIE-SYSNB-REV9-F-AFW, RIE-SYSNB-REV9-F-AFW and RIE-SYSNB-REV9-F-SWS) were corrected. This finding is considered closed.

Table 1: Resolution of the Farley PRA Peer Review F&Os Associated with the 17 Not Met SRs

F&O#	Review Element	Description	Resolution proposed by Peer Review	Resolution Status by SNC
HR-D2-01 HR-D2-02	HR-D2 (SR CCI) met CCI	Detailed HFE assessments are used for events that are not shown to be directly applicable to the analysis performed. Also, the screening values used for pre-HRAs are significantly lower than the ASEP values without justification of the values used.	Perform detailed analysis on all events to verify the applicability used or use screening values for those events not explicitly analyzed with a detailed analysis	A revision to Table 8-2 of the HRA notebook (RIE-NB-REV9-F-HRA) has been incorporated providing a more detailed explanation of the approach used. The pre-initiator approach relies on detailed THERP assessments that are mapped to similar HFEs. This finding is considered closed.
HR-G1-01	HR-G1 (SR CCI) met CCI	In general, detailed analysis is done for most post HRA events. However, the most important HRAs showing up in the cutset have not been performed on a detailed analysis.	Develop HRAs for the referenced 2 events and include in the HRA calculation	Included the events in the HRA calculator (Section 10.92 and 10.93) file using the values found in NUREG/CR-5500 and WCAP-15831. The finding is considered closed.

Table 1: Resolution of the Farley PRA Peer Review F&Os Associated with the 17 Not Met SRs				
F&O#	**Review Element**	**Description**	**Resolution proposed by Peer Review**	**Resolution Status by SNC**
HR-G7-01 HR-G7-02	HR-G7 QU-A5 QU-C2 (SR CCI/II/III) not met	The multiple human action analysis described in Appendix C does not appear to be used in the quantification. Attachment C to the HRA notebook performs the dependency assessment, but the dependency factors are based upon 2004 HRA values. The multiplication factors in the rule file are to be based upon current HRA. The top HRA cutset combinations in the QU notebook are not addressed in the HRA dependency analysis.	Explicitly evaluate the top HRA combinations in the dependency analysis. Update the HRA dependence evaluation to be consistent with industry practices	An HRA Dependency Analysis was conducted and incorporated into the Revision 9 model quantification. This analysis has been incorporated into the HRA notebook (RIE-NB-REV9-F-HRA) as Attachment C. The finding is considered closed.
HR-I3-01	HR-I3 (SR CCI/II/III) not met	Sources of uncertainty are not included in the HRA calculation similar to other Farley Unit 1 documentation.	Include a source of uncertainty in the HRA calculation	An HRA Dependency Analysis was conducted and incorporated into the Revision 9 model quantification. This analysis has been incorporated into the HRA notebook (RIE-NB-REV9-F-HRA) as Attachment C. The finding is considered closed.

Table 1: Resolution of the Farley PRA Peer Review F&Os Associated with the 17 Not Met SRs				
F&O#	**Review Element**	**Description**	**Resolution proposed by Peer Review**	**Resolution Status by SNC**
IFEV-B3-01	IFEV-B3 IFSO-B3 IFPP-B3 (SR CCI/II/III) not met	The Farley Unit 1 PRA flooding analysis indicates that sources of uncertainty were not documented because of the low contribution to CDF and LERF from flooding. Although this is true, the SR requires that a discussion of uncertainty be provided.	Include a discussion of uncertainty and assumptions related to internal flooding issues including partitioning, initiating events, and flood sources	New text concerning uncertainty and assumptions has been incorporated into the appropriate sections of the Flooding notebook. The finding is considered closed.
IFPP-B2-02 IFPP-B2-03	IFPP-B2 (SA CCI/II/III) not met	Internal flooding notebook provides the process and selection result of flood areas partitioning. However, there is no description about the reason for eliminating areas from further analysis, except containment.	Add information about the screened/eliminated areas and buildings in terms of internal flooding analysis	New text concerning screened/eliminated areas and buildings has been incorporated into the Section 3.1 of the Flooding notebook (RIE-NB-REV9-F-IF). The finding is considered closed.
IFQU-A7-01	IFQU-A7 (SA CCI/II/III) not met	Quantification of flooding event does not perform uncertainty analysis and dependency analysis.	Perform and provide uncertainty analysis and dependency analysis, even though the flood risk is not significant	An HRA Dependency Analysis was conducted and incorporated into the Revision 9 model quantification. This analysis will be incorporated into the HRA notebook (RIE-NB-REV9-F-HRA) as Appendix C. The finding is considered closed.

Table 1: Resolution of the Farley PRA Peer Review F&Os Associated with the 17 Not Met SRs				
F&O#	**Review Element**	**Description**	**Resolution proposed by Peer Review**	**Resolution Status by SNC**
IFSN-A4-01	IFSN-A4 (SR CCI/II/III) not met	In the IF Notebook, there was extensive discussion with respect to treatment of drains and explicit evidence that drains were considered as propagation paths for several flood scenarios. However, no explicit estimation of drain capacities could be found.	Add a table that explicitly includes drain capacities	New text has been incorporated in Table 6-1 through 6-4, Tables 7-1 through 7-4, Table 9-1, Section 12.3 of the Flooding notebook (RIE-NB-REV9-F-IF). The finding is considered closed.
IFSN-B3-01	IFSN-B3 (SR CCI/II/III) not met	There is no description about uncertainty.	Include a section in the IF Notebook to discuss the IF assumptions and sources of uncertainty	New text concerning uncertainty and assumptions has been incorporated into Sections 3.0, 4.1, 5.0, 6.0, 7.6, 8.4, 9.5, 10.3, 11.4, and 12.4 of the Flooding notebook (RIE-NB-REV9-F-IF). The finding is considered closed.
QU-F1-01	QU-F1 (SR CCI/II/III) not met	The mutually exclusive logic was generated by the procedure FNP-0-ACP-52.1 but was not documented in the quantification notebook.	Update the documentation to reflect the actual references	Documentation in reference has been updated in the Quantification Notebook (RIE-NB-REV9-F-QU). The finding is considered closed.
MU-B4-01	MU-B4 (SR CCI/II/III) not met	There is no reference to a peer review for upgrades. A section which addressed upgrades (not updates) to the PRA specific change in software used was not found.	Revise either NL-PRA-001 or NL-PRA-002 to explicitly require a peer review for PRA upgrades	Procedure RIE-001 (Section 4.2) was revised to require a peer review following an upgrade of the PRA model. The finding is considered closed.

A.3 Conclusion

The Farley Unit 1 and Unit 2 Internal Events PRA model is judged sufficient for the ILRT interval risk-informed application in accordance with Regulatory Guide 1.200, Revision 2.

Attachment 2

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5.5 Programs and Manuals

5.5.17 Containment Leakage Rate Testing Program (continued)

NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J," Revision 3-A, dated July 2012, and the conditions and limitations specified in NEI 94-01, Revision 2-A, dated October 2008.

Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in ~~Regulatory Guide 1.163, "Performance Based Containment Leak-Test Program," dated September 1995, as modified by the following exception to NEI 94-01, Rev. 0, "Industry Guidelines for Implementing Performance Based Option of 10 CFR 50, Appendix J":~~

~~Section 9.2.3: The next Type A test, after the March 1994 test for Unit 1 and the March 1995 test for Unit 2, shall be performed during refueling outage R22 (Spring 2009) for Unit 1 and during refueling outage R20 (Spring 2010) for Unit 2. This is a one time exception.~~

The peak calculated containment internal pressure for the design basis loss of coolant accident, P_a, is 43.8 psig.

The maximum allowable containment leakage rate, L_a, at P_a, is 0.15% of containment air weight per day.

Leakage rate acceptance criteria are:

a. Containment overall leakage rate acceptance criterion is $\leq 1.0\ L_a$. During plant startup following testing in accordance with this program, the leakage rate acceptance criteria are $\leq 0.60\ L_a$ for the combined Type B and C tests, and $\leq 0.75\ L_a$ for Type A tests;

b. Air lock testing acceptance criteria are:

   1. Overall air lock leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$.

   2. For each door, leakage rate is $\leq 0.01\ L_a$ when pressurized to ≥ 10 psig.

c. During plant startup following testing in accordance with this program, the leakage rate acceptance criterion for each containment purge penetration flowpath is $\leq 0.05\ L_a$.

The provisions of SR 3.0.2 do not apply to the test frequencies specified in the Containment Leakage Rate Testing Program.

The provisions of SR 3.0.3 are applicable to the Containment Leakage Rate Testing Program.

(continued)

Attachment 3

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5.5 Programs and Manuals

5.5.17 Containment Leakage Rate Testing Program (continued)

Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in NEI-94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR 50 Appendix J," Revision 3-A, dated July 2012, and the conditions and limitations specified in NEI 94-01, Revision 2-A, dated October 2008.

The peak calculated containment internal pressure for the design basis loss of coolant accident, P_a, is 43.8 psig.

The maximum allowable containment leakage rate, L_a, at P_a, is 0.15% of containment air weight per day.

Leakage rate acceptance criteria are:

a. Containment overall leakage rate acceptance criterion is $\leq 1.0\ L_a$. During plant startup following testing in accordance with this program, the leakage rate acceptance criteria are $\leq 0.60\ L_a$ for the combined Type B and C tests, and $\leq 0.75\ L_a$ for Type A tests;

b. Air lock testing acceptance criteria are:

   1. Overall air lock leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$.

   2. For each door, leakage rate is $\leq 0.01\ L_a$ when pressurized to ≥ 10 psig.

c. During plant startup following testing in accordance with this program, the leakage rate acceptance criterion for each containment purge penetration flowpath is $\leq 0.05\ L_a$.

The provisions of SR 3.0.2 do not apply to the test frequencies specified in the Containment Leakage Rate Testing Program.

The provisions of SR 3.0.3 are applicable to the Containment Leakage Rate Testing Program.

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5.5.17 Containment Leakage Rate Testing Program (continued)

Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in NEI-94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR 50 Appendix J," Revision 3-A, dated July 2012, and the conditions and limitations specified in NEI 94-01, Revision 2-A, dated October 2008.

The peak calculated containment internal pressure for the design basis loss of coolant accident, P_a, is 43.8 psig.

The maximum allowable containment leakage rate, L_a, at P_a, is 0.15% of containment air weight per day.

Leakage rate acceptance criteria are:

a. Containment overall leakage rate acceptance criterion is $\leq 1.0\ L_a$. During plant startup following testing in accordance with this program, the leakage rate acceptance criteria are $\leq 0.60\ L_a$ for the combined Type B and C tests, and $\leq 0.75\ L_a$ for Type A tests;

b. Air lock testing acceptance criteria are:

   1. Overall air lock leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$.

   2. For each door, leakage rate is $\leq 0.01\ L_a$ when pressurized to ≥ 10 psig.

c. During plant startup following testing in accordance with this program, the leakage rate acceptance criterion for each containment purge penetration flowpath is $\leq 0.05\ L_a$.

The provisions of SR 3.0.2 do not apply to the test frequencies specified in the Containment Leakage Rate Testing Program.

The provisions of SR 3.0.3 are applicable to the Containment Leakage Rate Testing Program.

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