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10 CFR 50.90

November 8, 2019
Serial: RA-19-0067

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

Shearon Harris Nuclear Power Plant, Unit 1
Docket No. 50-400/Renewed License No. NPF-63

Subject: License Amendment Request to Revise Technical Specifications for the Adoption of 10 CFR 50, Appendix J, Option B for Type B and C Testing and for Permanent Extension of Type A, B and C Leak Rate Test Frequencies

Ladies and Gentlemen:

Pursuant to 10 CFR 50.90, Duke Energy Progress, LLC (Duke Energy), hereby requests a revision to the Technical Specifications (TS) for the Shearon Harris Nuclear Power Plant, Unit 1 (HNP). The proposed change would revise TS 6.8.4.k, "Containment Leakage Rate Testing Program," and TS 3/4.6.1, “Primary Containment,” to allow the following:

- Increase the existing Type A integrated leakage rate test (ILRT) program test interval from 10 years to 15 years,

- Adoption of 10 CFR 50, Appendix J, Option B, as modified by approved exemptions, for the performance-based testing of Type B and C tested components,

- Adopt an extension of the containment isolation valve leakage rate testing frequency for Type C leakage rate testing of selected components,

- 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 allowable test interval extension of nine months for Type A, Type B and Type C leakage rate tests.

The enclosure provides a description and assessment of the proposed change. In accordance with 10 CFR 50.91(a), the enclosure also provides the basis for Duke Energy’s determination that the proposed change to the TS does not involve a significant hazards consideration. Attachment 1 to the enclosure provides a copy of the proposed TS changes. Attachment 2 to the enclosure provides a copy of the proposed TS Bases changes for information purposes only. Attachment 3 provides an evaluation of the risk significance of the proposed change.

Approval of the proposed amendment is requested within one year of completion of the NRC's acceptance review. Once approved, the amendment shall be implemented within 120 days.

There are no regulatory commitments made in this submittal.

In accordance with 10 CFR 50.91(b)(1), Duke Energy is notifying the State of North Carolina of this license amendment request by transmitting a copy of this letter and enclosure, with attachments, to the designated State Official.

Should you have any questions regarding this submittal, or require additional information, please contact Art Zaremba, Manager – Nuclear Fleet Licensing, at (980) 373-2062.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on November 8 , 2019.

Sincerely,

Tanya M Hamilton

Tanya M. Hamilton

Enclosure:

Description and Assessment of the Proposed Change

Attachment 1: Proposed Technical Specification Changes (Mark-up)
Attachment 2: Proposed Technical Specification Bases Changes (Mark-up) (For Information Only)
Attachment 3: Shearon Harris Nuclear Power Plant: Evaluation of Risk Significance of Permanent ILRT Extension

cc: J. Zeiler, NRC Senior Resident Inspector, HNP
W. L. Cox, III, Section Chief N.C. DHSR
T. Hood, NRC Project Manager, HNP
L. Dudes, NRC Regional Administrator, Region II

Evaluation of the Proposed Change

SUBJECT: License Amendment Request to Revise Technical Specifications for the Adoption of 10 CFR 50, Appendix J, Option B for Type B and C Testing and for Permanent Extension of Type A, B and C Leak Rate Test Frequencies



Attachments:

1. Proposed Technical Specification Changes (Mark-up)
2. Proposed Technical Specification Bases Changes (Mark-up)
3. Shearon Harris Nuclear Power Plant: Evaluation of Risk Significance of Permanent ILRT Extension

## 1.0 SUMMARY DESCRIPTION

In accordance with 10 CFR 50.90, “Application for amendment of license, construction permit, or early site permit,” Duke Energy Progress, LLC (Duke Energy), requests an amendment to the Shearon Harris Nuclear Power Plant, Unit 1 (HNP) Renewed Facility Operating License No. NFP-63. Specifically, the proposed change is a request to revise Technical Specifications (TS) 6.8.4.k, “Containment Leakage Rate Testing Program,” and TS 3/4.6.1, “Primary Containment,” 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 2), and the conditions and limitations specified in NEI 94-01, Revision 2-A (Reference 8).

- Replace the commitment to 10 CFR 50 Appendix J, Option A for Type B and Type C testing with the adoption of 10 CFR 50, Appendix J, Option B, as modified by approved exemptions, for the performance-based testing of Types B and C tested components in accordance with the guidance of Technical Specification Task Force (TSTF)-52, “Implement 10 CFR 50, Appendix J, Option B” (Reference 44).

- 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 30).

- 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 would revise HNP TS 6.8.4.k by replacing the reference to Regulatory Guide (RG) 1.163, Performance-Based Containment Leak-Test Program, (Reference 1) and 10 CFR 50, Appendix J, Option A 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 (Reference 8), dated October 2008, as the implementation documents used by HNP to implement the performance-based leakage testing program in accordance with 10 CFR 50, Appendix J, Option B. This license amendment request (LAR) also proposes an administrative change to TS 6.8.4.k to delete the information regarding the performance of the next HNP Type A test to be performed no later than May 23, 2012, as this Type A test has already occurred.

The proposed change to the TS 6.8.4.k contained herein would also revise HNP TS Limiting Condition for Operation (LCO) 3.6.1.2 and TS Surveillance Requirements (SR) 4.6.1.1.c, 4.6.1.2, 4.6.1.3.a and 4.6.1.6.1 by replacing the references to 10 CFR 50, Appendix J, Option A with a reference to the Containment Leakage Rate Testing (CLRT) Program and incorporate the changes recommended by TSTF-52, Revision 3, as applicable to HNP.

The associated TS Bases for LCO 3.6.1.2 and SR 4.6.1.2 are also being revised to reflect the proposed change to remove references to 10 CFR 50, Appendix J, Option A for Type B and C tests as well as incorporate the bases changes recommended by TSTF-52, Revision 3, as applicable to HNP.

Attachment 3 contains the plant specific risk assessment conducted to support this proposed change. This risk assessment followed the guidelines of Nuclear Regulatory Commission (NRC) RG 1.174, Revision 3 (Reference 39) and RG 1.200, Revision 2 (Reference 4). The risk assessment concluded that increasing the ILRT frequency on a permanent basis from a one-in-ten-year frequency to a one-in-fifteen-year frequency is considered to represent a small change in the HNP risk profile.

## 2.0 DETAILED DESCRIPTION

The HNP TS 6.8.4.k, "Containment Leakage Rate Testing Program," currently states, in part:

> A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54 (o) and 10 CFR 50 Appendix J, Option B, as modified by approved exemptions. This program shall be in conformance with the NRC Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995, with the following exceptions noted:
>
> 1) The above Containment Leakage Rate Testing Program is only applicable to Type A testing. Type B and C testing shall continue to be conducted in accordance with the original commitment to 10 CFR 50 Appendix J, Option A.
>
> 2) The first Type A test performed after the May 23, 1997 Type A test shall be performed no later than May 23, 2012.
>
> 3) Visual examination of the containment system shall be in accordance with Specification 4.6.1.6.1.
>
> The calculated peak containment internal pressure related to the design basis loss-of-coolant accident is 41.8 psig. The calculated peak containment internal pressure related to the design basis main steam line break is 41.3 psig. $P_a$ will be assumed to be 41.8 psig for the purpose of containment testing in accordance with this Technical Specification.
>
> The maximum allowable containment leakage rate, $L_a$ at $P_a$, shall be 0.1 % of containment air weight per day.

The containment overall leakage rate acceptance criterion is ≤ 1.0 $L_a$. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are ≤ 0.60 $L_a$ for the combined Type B and Type C tests, and ≤ 0.75 $L_a$ for Type A tests.

The provisions of Surveillance Requirement 4.0.2 do not apply to the test frequencies specified in the Containment Leakage Rate Testing Program. However, test frequencies specified in this Program may be extended consistent with the guidance provided in Nuclear Energy Institute (NEI) 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR 50 Appendix J," as endorsed by Regulatory Guide 1.163. Specifically, NEI 94-01 has this provision for test frequency extension:

1) Consistent with standard scheduling practices for Technical Specifications Required Surveillances, intervals for recommended Type A testing may be extended by up to 15 months. This option should be used only in cases where refueling schedules have been changed to accommodate other factors.

The provisions of Surveillance Requirement 4.0.3 are applicable to the Containment Leakage Rate Testing Program.

The proposed changes to HNP TS 6.8.4.k will replace the reference to RG 1.163 and the commitment to 10 CFR 50, Appendix J, Option A, with reference to NEI Topical Report NEI 94-01, Revisions 2-A and 3-A.

The proposed changes are requested as part of the implementation of 10 CFR 50, Appendix J, Option B, as described in TSTF-52 (Reference 44), as applicable to HNP.

Additionally, this LAR incorporates an administrative change to TS 6.8.4.k to delete exception No. 2 regarding the performance of the next HNP Type A test no later than May 23, 2012. This change will have no impact on the HNP 10 CFR 50, Appendix J Testing Program requirements as this date has already occurred and the Type A test has already been performed. This Type A test requirement had been previously approved by the NRC in Amendment No. 122 (Reference 13) and is no longer applicable since the test date occurred in the past. Therefore, TS 6.8.4.k exception 2 will be deleted in its entirety, as it is no longer applicable.

The proposed change revises HNP TS 6.8.4.k to read as follows (with recommended changes using strike-out for deleted text and **bold-type** to show new text insertions, for clarification purposes):

A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54 (o) and 10 CFR 50 Appendix J, Option B, as modified by approved exemptions. This program shall be in ~~conformance with the NRC Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995,~~ **accordance with the guidelines contained in 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, dated July 2012, and the conditions and limitations specified in NEI 94-01, Revision 2-A, dated October 2008,** with the following exception~~s~~ noted:

1) ~~The above Containment Leakage Rate Testing Program is only applicable to Type A testing. Type B and C testing shall continue to be conducted in accordance with the original commitment to 10 CFR 50 Appendix J, Option A.~~

~~2) The first Type A test performed after the May 23, 1997 Type A test shall be performed no later than May 23, 2012.~~

~~3)~~ Visual examination of the containment system shall be in accordance with Specification 4.6.1.6.1.

The calculated peak containment internal pressure related to the design basis loss-of-coolant accident is 41.8 psig. The calculated peak containment internal pressure related to the design basis main steam line break is 41.3 psig. $P_a$ will be assumed to be 41.8 psig for the purpose of containment testing in accordance with this Technical Specification.

The maximum allowable containment leakage rate, $L_a$ at $P_a$, shall be 0.1 % of containment air weight per day.

**Leakage rate acceptance criteria:**

**1)** The containment ~~overall~~ leakage rate acceptance criterion is $\leq 1.0\ L_a$. During the first unit 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 Type C tests, and $\leq 0.75\ L_a$ for Type A tests.

2) **Air lock testing acceptance criteria are:**

a) **Overall air lock leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$.**

b) **For each door, leakage rate is $\leq 0.01\ L_a$ when pressurized to $\geq P_a$.**

~~The provisions of Surveillance Requirement 4.0.2 do not apply to the test frequencies specified in the Containment Leakage Rate Testing Program. However, test frequencies specified in this Program may be extended consistent with the guidance provided in Nuclear Energy Institute (NEI) 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR 50 Appendix J," as endorsed by Regulatory Guide 1.163. Specifically, NEI 94-01 has this provision for test frequency extension:~~

~~1) Consistent with standard scheduling practices for Technical Specifications Required Surveillances, intervals for recommended Type A testing may be extended by up to 15 months. This option should be used only in cases where refueling schedules have been changed to accommodate other factors.~~

The provisions of Surveillance Requirement 4.0.3 are applicable to the Containment Leakage Rate Testing Program.

**Nothing in these Technical Specifications shall be construed to modify the testing frequencies required by 10 CFR 50, Appendix J.**

This LAR also proposes revisions to HNP TS SR 4.6.1.1.c, LCO 3.6.1.2, SR 4.6.1.2, SR 4.6.1.3.a, and SR 4.6.1.6.1 to read as follows (with recommended changes using strike-out for deleted text and **bold-type** to show new text insertions, for clarification purposes):

4.6.1.1 Primary CONTAINMENT INTEGRITY shall be demonstrated:

c. ~~After each closing of each penetration subject to Type B testing, except the containment air locks, if opened following a Type A or B test, by leak rate testing the seal with gas at a pressure not less than~~ ~~$P_a$,~~ ~~and verifying that when the measured leakage rate for these seals is added to the leakage rates determined pursuant to Specification 4.6.1.2a. for all other Type B and C penetrations, the combined leakage rate is less than 0.60~~ ~~$L_a$.~~ **By performing required visual examinations and leakage rate testing, except for containment air lock testing, in accordance with the Containment Leakage Rate Testing Program.**

LIMITING CONDITION FOR OPERATION

3.6.1.2 Containment leakage rates shall be ~~limited to:~~ **within the limits specified in the Containment Leakage Rate Testing Program.**

~~a. An overall integrated leakage rate within limits specified in the Containment Leakage Rate Testing Program.~~

~~b. A combined leakage rate of less than or equal to 0.60~~ ~~$L_a$~~ ~~for all penetrations and valves subject to Type B and C tests, when pressurized to~~ ~~$P_a$.~~

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

With ~~either the measured overall integrated containment leakage rate exceeding 0.75 $L_a$, or the measured combined leakage rate for all penetrations and valves subject to Types B and C tests exceeding 0.60 $L_a$, restore the overall integrated leakage rate to less than 0.75 $L_a$, and the combined leakage rate for all penetrations subject to Type B and C tests to less than 0.60 $L_a$~~ **containment leakage rate not within the limits specified in the Containment Leakage Rate Testing Program, restore the leakage rate to within the limits specified in the Containment Leakage Rate Testing Program** prior to increasing the Reactor Coolant System temperature above 200°F.

SURVEILLANCE REQUIREMENTS

4.6.1.2 The ~~Type A~~ containment leakage rate tests shall be performed in accordance with the Containment Leakage Rate Testing Program described in Technical Specification 6.8.4.k. ~~The Type B and Type C containment leakage rate tests shall be demonstrated at the test schedule and shall be determined in conformance with the criteria specified in 10 CFR 50 Appendix J, Option A.~~

~~a. Type B and C tests shall be conducted with gas at a pressure not less than $P_a$, at intervals no greater than 24 months except for tests involving:~~

~~1. Air locks,~~

~~2. Containment purge makeup and exhaust isolation valves with resilient material seals;~~

~~b. Air locks shall be tested and demonstrated OPERABLE by the requirements of Specification 4.6.1.3;~~

~~c. Purge makeup and exhaust isolation valves with resilient material seals shall be tested and demonstrated OPERABLE by the requirements of Specification 4.6.1.7.2;~~

~~d. The provisions of Specification 4.0.2 are not applicable.~~

SURVEILLANCE REQUIREMENTS

4.6.1.3 Each containment air lock shall be demonstrated OPERABLE by:

a. Performing required air lock leakage rate testing in accordance with ~~10 CFR 50, Appendix J~~ **the Containment Leakage Rate Testing Program**, as modified by **the** approved exemptions###. ~~The acceptance criteria for air lock testing are:~~

~~1. Overall air lock leakage rate is ≤ .05 $L_a$ when tested at ≥ $P_a$.~~

~~2. For each door, leakage rate is ≤ .01 $L_a$ when tested at ≥ $P_a$.~~

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### ~~1.~~ An inoperable air lock door does not invalidate the previous successful performance of the overall airlock leakage test.

~~2. Results shall be evaluated against Specification 3.6.1.2.a in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions.~~

SURVEILLANCE REQUIREMENTS

4.6.1.6.1 Containment Vessel Surfaces. The structural integrity of the exposed accessible interior and exterior surfaces of the containment vessel, including the liner plate, shall be determined, during the shutdown for each Type A containment leakage rate test (reference Specification ~~4.6.1.2~~ **4.6.1.1.c**), by a visual inspection of these surfaces. This inspection shall be performed prior to the Type A containment leakage rate test to verify no apparent changes in appearance or other abnormal degradation. Additional inspections shall be conducted in accordance with Subsections IWE and IWL of the ASME Boiler and Pressure Vessel Code, Section XI.

A mark-up of the affected TS pages are provided in Attachment 1. Additionally, a mark-up of the TS Bases pages are provided in Attachment 2 for information only.

## 3.0 TECHNICAL EVALUATION

### 3.1 DESCRIPTION OF PRIMARY CONTAINMENT SYSTEM

The Concrete Containment Structure (CCS) is a steel lined reinforced concrete structure in the form of a vertical right cylinder with a hemispherical dome and a flat base with a recess beneath the reactor vessel. No pre-stressing tendon system is employed in the containment design and construction.

The structure consists of a cylindrical wall measuring 160 ft. in height from the liner on the base to the springline of the dome and has an inside diameter of 130 ft. The cylinder wall is 4 ft.-6 in. thick. The inside radius of the 2 ft.-6 in. thick dome is equal to that of the cylinder so that the discontinuity at the spring line due to the change in thickness is on the outer surface. The base mat consists of a 12 ft. thick structural concrete slab and a metal liner. The liner is welded to inserts embedded in the concrete slab. The base liner is covered with concrete, the top of which forms the floor of the containment. The base mat is supported by sound rock.

The basic structural elements considered in the design of the containment structure are the basemat, cylinder wall, and dome. These act essentially as one structure under all loading conditions. The nominal liner plate is 3/8 in. thick in the cylinder, 1/4 in. thick on the bottom, and 1/2 in. thick in the dome. The liner is anchored to the concrete shell by means of anchor studs fusion welded to the liner plate so that it forms an integral part of the containment structure. The liner functions primarily as a leaktight membrane. An impervious plastic waterproofing membrane is located between the containment foundation mat and the ground. Before laying the membrane, a concrete leveling surface was placed on the rock. After installing the membrane, a concrete protective layer was installed before placing reinforcement for the foundation mat. The waterproofing membrane for the Containment Building is continuous under the containment foundation mat and terminates into waterstops at the joints with adjacent structures.

**Containment Foundation**

The foundation mat is a conventionally reinforced concrete mat of circular shape and 12 ft. uniform thickness. The top of the mat is 44 ft. below finished grade.

The entire mat is structurally independent of adjacent Seismic Category I foundations. The mat has a recess in the central portion to house the reactor pressure vessel. In the engineered safety features (ESF) area, there is a recess to house the ESF system sumps for the containment spray header water, which exits the containment through two collection sumps and embedded drainpipes.

The foundation mat, inside the containment and including the reactor cavity, is covered with 1/4 in. thick carbon steel liner plate, except at the connection with the wall liner plate, where a 3/8 in. (nominal) thick liner plate is provided. A 5 ft. thick concrete internal mat is provided over the liner for protection and support of internal primary and secondary shield walls.

In order to protect the mat liner plate against groundwater hydrostatic pressure, an impervious waterproofing membrane was placed continuously below the foundation mat and terminates into waterstops at the joints with adjacent structures. The seismic gaps between adjacent structures are cut off from groundwater by double rows of horizontal waterstops. Any leakage through the waterproofing membrane will be drained through porous concrete drains placed between the membrane and the concrete mat.

The primary and secondary shield walls are supported by the internal foundation mat, which in turn is resting on the external foundation mat. No anchorage of the interior structures through the liner plate and into the external mat is provided.

**Cylindrical Wall**

The reinforced concrete cylindrical wall is designed to withstand the loadings and stresses anticipated during the operating life of the plant. The steel liner is attached to, and supported by, the concrete. The liner functions primarily as a gas-tight membrane and also transmits loads to the concrete. During construction, the steel liner serves as the inside form for the concrete wall and dome. The containment structure does not require the participation of the liner as a structural component.

Hoop tension in the cylindrical concrete wall is resisted by horizontal reinforcing bars near both the outer and inner surfaces of the wall.

Horizontal circumferential bars, including those in the dome, have their splices staggered wherever possible.

Longitudinal tension in the cylindrical wall is resisted by rows of vertical reinforcing bars placed near the interior and exterior faces of the wall, with cadweld splices staggered whenever practical.

Reinforcing steel, which terminates in locations where biaxial tension is predicted, such as at penetrations, is anchored by hooks, bends, or positive mechanical anchorage in such a manner that the force in the terminated bar is adequately transferred to other reinforcement. Also, bar development length at such location is increased.

The main vertical and hoop reinforcing steel in the containment wall and dome have a concrete cover of 6-1/2 inches and 2-3/4 inches, respectively, with concrete cover governed by provisions listed in the ASME/ACI 359 Code.

The juncture of the cylinder to the base slab is considered as rigidly connected. The cylinder at this point cannot expand but joint rotation is considered as the wall deforms under the internal pressure, temperature, and dead load conditions; hence, radial shear and moments are introduced into the cylinder wall. All the radial shears at the base of the cylinder wall are resisted by reinforcing steel. This shear reinforcing is horizontal.

The concrete thickness of the wall is increased from 4 ft.-6 in. to 6 ft.-6 in. around the major penetrations such as the equipment hatch, personnel lock, emergency air lock, main steam penetrations, and feedwater penetrations. In all of these areas, the main hoop and vertical reinforcement are bent around openings, hooked into the wall, or terminated using a mechanical embedment. Additional circular radial and shear reinforcement is provided to withstand stress concentrations and additional radial and in-plane shear developed in these areas by the loading combinations.

**Liner Plate**

A continuous welded steel liner plate is provided on the entire inside face of the concrete containment cylindrical wall to limit the release of radioactive materials into the environment. The thickness of the liner in the cylindrical wall area is 3/8 in. nominal. A 1 in. thick liner plate is provided at the crane girder brackets elevation. Ring collars up to 2 in. thick are provided around all penetrations and shop welded to the penetration sleeves, as required by ASME Section III, Division 2/ACI 359 Code, Section CC4552.2.1.

An anchorage system, consisting of Nelson Studs 5/8 in. diameter by 4 in. long, is provided to prevent instability of the liner for all load combinations.

In order to minimize liner stresses, strains and deformations under the design loading condition, the cylindrical wall liner plate connection with the foundation mat lower plate is an unanchored embedded 90-degree free-standing welded connection. No anchor studs are provided on a 5 ft. vertical portion and on a 3 ft. horizontal portion of the liner plate. In order to allow free deformation of the liner plate during test pressure conditions, an inch of ethafoam is provided on the inside face of the liner plate facing the concrete of the internal mat. In order to allow vertical movement at the concrete connection during the same test pressure conditions, ethafoam is also provided against the back-up plate and the end of the horizontal liner plate.

The 1 in. liner plate at the crane girder brackets area is anchored into the concrete wall with shear lugs, anchor bolts connected to embedded plates, special anchorages, and Nelson studs in order to withstand the complexity of loading induced during operation of the crane and/or seismically induced loads.

Leak chase channels or angles are provided at the liner seams for leak tightness examination.

There are no through liner attachments. The supports for heating, ventilation and air conditioning (HVAC) ducts, piping hangers, and ladders, are welded to the liner plate, which is locally reinforced with additional studs in the region of surface attachments.

**Containment Dome**

The containment dome is a lined reinforced concrete hemispherical dome of 2 ft. 6 in. uniform thickness. A continuous welded steel liner plate, one-half inch thick, is provided on the inside face of the dome. Nelson studs 5/8 in. diameter by 4 in. long are used to connect the liner to the concrete.

The reinforced concrete dome is designed to withstand the loads anticipated during the operating life of the plant and postulated accidents and events. Meridional and circumferential reinforcing bars are provided to resist the refueling tensile forces and bending moments.

The dome reinforcement consists of layers of reinforcing steel placed meriodionally, extending from the vertical reinforcing of the cylindrical wall, and horizontal layers of circumferential bars. The layers are located near both the inner and outer faces of the concrete. The radial pattern of the meridional reinforcing steel, terminating in the containment dome, results in a high degree of redundancy of reinforcing steel in the dome. Bars are terminated beyond a point where there is more than twice the amount of steel required for design purposes. The rate of convergence of these bars, and the low stress requirements dictated by this arrangement, results in a satisfactory development length of the meridional reinforcing bars. Near the crown of the dome, the meridional reinforcing bars are welded to a steel hub plate, cast in the concrete, concentric with the dome centerline.

**Containment Penetrations**

Equipment Hatch

The equipment hatch is a welded steel assembly having an inside diameter of 24 ft. 0 in. with a weld-on cover with sufficient material to initially allow for six removals and re-welding. As a result of the steam generator replacement (SGR) activities, one removal and re-welding has been performed and five remain on the equipment hatch. A 15 ft.-0 in. inside diameter (ID) bolted cover is provided in the equipment hatch cover for passage of smaller equipment during plant operation. Provision is made to pressurize the space between the gaskets of the bolted hatch cover to meet the requirements of 10 CFR 50, Appendix J.

The containment equipment hatch is provided with external missile protection.

Personnel Air Locks

One breech-type personnel air lock and one personnel emergency air lock are provided. Each lock is a welded steel assembly having two doors which are double-gasketed with material resistant to radiation. Provisions are made to pressurize the space between the gaskets. The doors of each lock are equipped with quick acting valves for equalizing the pressure across each door and the doors are not operable unless pressure is equalized.

The breech-type personnel air lock has a 9 ft.-0 in. ID with full diameter breech doors to open outwardly from each end of the lock. Doors for the lock are hydraulically sealed and electrically interlocked.

The personnel emergency air lock has an outside diameter (OD) of 5 ft.-0 in. with a 2 ft.-6 in. diameter door located at each end of the lock. The doors of the lock are in series and are mechanically interlocked to ensure that one door cannot be opened until the second door is sealed.

There is visual indication outside each door showing whether the opposite door is open or closed and whether its valve is open or closed. Provisions have been made outside each door for remotely closing the opposite door so that in the event that one door is accidently left open, it can be closed by remote control.

Mechanical Penetrations

Mechanical penetrations are divided into two general types:

- Type I – High pressure, high temperature piping (above 200°F).
- Type II – General piping (penetrations which are subject to only relatively small pipe rupture forces and temperatures up to 200°F).

Type I mechanical piping hot penetrations are provided for high pressure and high temperature (above 200°F) lines, which penetrate the concrete containment structure. The process pipe is connected to a containment penetration sleeve (which is partially embedded in the concrete wall) by a forged flued head fitting. The flued head fittings are designed to carry the forces and moments due to the normal operating conditions and due to the postulated pipe rupture loads by transferring these forces to the containment penetration sleeves and further into the concrete containment wall.

Type II mechanical piping cold penetrations are provided for low temperature (below 200°F) lines which penetrate the concrete containment structure. The process pipe passes through a containment penetration sleeve which is partially embedded and anchored into the concrete wall. The annular gap between the process pipe and the sleeve is sealed on both the inside and outside faces of the concrete wall. The inside plate is designed to withstand the internal pressure and to transfer all of the normal operating loads and/or the postulated accident piping rupture loads from the piping system to the penetration sleeve and then into the concrete wall. The outside seal is flexible to accommodate thermal expansion movements.

Type II penetrations also include HVAC penetrations and groups of small diameter lines (instrument, sampling lines) which incorporate socket weld couplings welded to closure plates. Two categories of penetrations are included in Type II penetrations: Type IIA for single tubing or multiple pipes and/or tubings, and Type IIB for single pipe.

HVAC penetration sleeves, 48 in. and 24 in. diameter, are mechanical Type II penetration sleeves.

<u>Fuel Transfer Tube</u>

A fuel transfer penetration is provided to transport fuel assemblies between the refueling cavity in the containment and the fuel transfer canal in the Fuel Handling Building. This penetration consists of a 20 in. diameter stainless steel pipe installed inside a 26 in. pipe. The inner pipe acts as the transfer tube and is fitted with a double-gasketed blind flange in the refueling cavity and a standard gate valve in the fuel transfer canal. This arrangement prevents leakage through the transfer tube in the event of an accident.

The penetration sleeve is welded to the steel liner and anchored into the concrete wall. Provision is made for testing welds essential to the integrity of the liner. Bellows expansion joints are provided to compensate for any differential movement between the structures due to operating thermal expansion and seismic movements.

The fuel transfer tube expansion joints are not part of the containment pressure boundary; rather, the transfer tube is rigidly attached to the containment penetration sleeve. Two bellows type expansion joints are installed, with the first forming a flexible joint between the transfer tube and the transfer canal inside the containment, and the second forming a flexible joint between the transfer tube and the Fuel Handling Building fuel transfer canal.

Sump Line Valve Chambers

There are four valve chambers and their appurtenances. The valve chambers and their appurtenances are 9 ft.-0 in. diameter by 19 ft.-0 in. long airtight enclosures which function as a secondary containment boundary to completely enclose the containment sump lines and isolation valves.

Electrical Penetrations

Electrical penetrations are included within the Type III penetrations. Modular type penetrations are used for all electrical conductors passing through the containment wall. Each penetration assembly consists of a stainless steel header plate attached to a carbon steel welded ring, which is in turn welded to the pipe sleeve. The header plate accepts either three or six modules depending on the penetration diameter and voltage classification.

The modules are held in the header plates by means of retaining clamps. Each module is a hollow cylinder through which the conductors pass. The conductors are hermetically sealed into the module with an epoxy compound. Each module is provided with a pressure connection to allow pressurization for testing.

The header plates are attached to penetration sleeves located in the wall of the containment vessel and welded to the containment liner. Sealing between the header plates and the sleeves is accomplished by welding. All materials used in the design are selected for compatibility with all possible environmental conditions during normal, accident, or post-accident periods. Spare electrical penetration sleeves are provided for possible future uses. Each penetration is sealed and tested at the factory for leakage. The only seals that need to be made in the field are the welds attaching the header plates to the sleeves.

### 3.1.1 CONTAINMENT ISOLATION SYSTEM

The Containment Isolation System consists of the valves and actuators required to isolate the containment following a loss-of-coolant accident (LOCA), steam line rupture, or fuel handling accident inside the containment.

The Containment Isolation System is designed to the following bases:

- The Containment Isolation System provides isolation of lines penetrating containment, which are not required to be open for operation of the ESF Systems, to limit the release of radioactive materials to the atmosphere during a LOCA.

- Upon failure of a main steam line, the Main Steam Line Isolation System isolates the faulted steam generator (SG) to prevent excessive cooldown of the Reactor Coolant System (RCS) or overpressurization of the containment, and the Containment Isolation System isolates the containment.

- Upon failure of a main feedwater line, the Main Feedwater Isolation System isolates the faulted SG, and the Containment Isolation System isolates the containment.

- Upon detection of high containment atmosphere radioactivity, isolation valves in the Containment Atmosphere Purge Exhaust System are shut to control release of radioactivity to the environment.

  All containment purge and vent isolation valves, with the exception of those serving the Hydrogen Purge System, close automatically on a high radiation signal generated as a result of inputs from containment airborne radiation sensors. All automatically actuated valves have status indication lights in the Main Control Room.

- The Containment Isolation System is designed in accordance with 10 CFR 50, Appendix A, General Design Criterion (GDC) 54 and Westinghouse Systems Standard Design Criteria, Number 1.14, Revision 2.

- There are no lines that are part of the reactor coolant pressure boundary (RCPB) that penetrate the Containment (i.e., no safety class 1 lines); therefore, GDC 55 is not applicable to HNP. However, for lines such as charging, safety injection, and letdown, there is not an applicable GDC because these lines are connected to the RCPB but are not part of the RCPB. Each line that is connected to the RCPB and instrument lines is provided with CIVs in accordance with 10 CFR 50, Appendix A, GDC 55, with the exception of the residual heat removal (RHR) hot leg suction lines.

- Each line that connects directly to the containment atmosphere and penetrates containment, with the exception of the RHR and Containment Spray (CS) recirculation sump lines, and instrument lines is provided with CIVs in accordance with 10 CFR 50, Appendix A, GDC 56.

- Each line that forms a closed system inside containment, with the exception of the containment pressure sensing lines, is provided with CIVs in accordance with 10 CFR 50, Appendix A, GDC 57.

- Emergency power from the diesel generators is provided to ensure system operation in the event of a loss of offsite power.

- All air/spring-actuated valves are designed to fail to their required position to perform their safety function upon loss of the instrument air supply and/or electrical power.

- The Containment Isolation System design is such that the containment design leakage rate is not exceeded during a design basis accident (DBA).

- The Containment Isolation System is designed to remain functional during and following the safe shutdown earthquake.

- Closure times for CIVs are established on the basis to minimize the release of containment atmosphere to the environment, to mitigate the offsite radiological consequences, and to assure that emergency core cooling system (ECCS) effectiveness is not degraded by a reduction in the containment back-pressure.

- Relief valves, which are located between CIVs, are designed to meet the requirements for CIVs.

- The SG shell and lines connected to the secondary side of the SG are considered to be an extension of the containment and, therefore, need no CIVs located inside the containment.

- The welding and qualification requirements for all welds associated with the spare penetration sleeve assemblies are in accordance with the appropriate requirements of Section III of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code. Provisions are made for leak testing the weld between the closure plate/cap and the embedded wall sleeve.

- The containment setpoint pressure that initiates containment isolation for nonessential penetrations must be reduced to the minimum compatible with normal operating conditions. A conservative value of 3.0 psig was established based on inputs to the HNP containment accident analysis. This value was selected to optimize: a) ability of safety injection systems to maintain containment within maximum allowable pressure, and b) provide sufficient response time for instruments.

  The pressure setpoint is above the maximum expected pressure inside containment during normal operation so that inadvertent containment isolation will not occur during normal operation as a result of instrument drift, pressure fluctuations, and instrument errors.

### 3.1.2 Containment Overpressure on ECCS Performance

<u>Containment Spray System (CSS) Pumps</u>

The Net Positive Suction Head (NPSH) requirements of the CS pumps have been evaluated for both the injection and recirculation phases following a LOCA.

The formulae and parameters used in the evaluation of the NPSH during both the injection and recirculation phases are the same as in the case of the low head injection pumps. No reliance is placed on the containment pressure for meeting the NPSH requirements for the CS pumps; however, credit is taken for the pressure necessary to maintain the fluid in its liquid phase (i.e., liquid vapor pressure).

Residual Heat Removal Pumps

In the event of a LOCA, the RHR pumps are started automatically on receipt of an "S" signal. The RHR pumps take suction from the refueling water storage tank (RWST) during the injection phase and from the containment sump during the recirculation phase. Each RHR pump is a single stage, vertical position centrifugal pump.

The safety intent of RG 1.1 (Reference 46) is met by the design of the ECCS such that adequate NPSH is provided to system pumps. The most limiting condition with respect to NPSH exists when the RHR pumps are switched to the recirculation mode of operation. In addition to considering the static head and suction line pressure drop, the calculation of available NPSH in the recirculation mode assumes that the vapor pressure of the liquid in the sump is equal to the containment ambient pressure. This ensures that the actual available NPSH is always greater than the calculated NPSH.

ECCS pump specifications include a specified maximum required NPSH which the pump is required to meet. Pump vendors have verified that the required NPSH for the HNP pumps is less than the maximum required NPSH through testing in accordance with the criteria established by the Hydraulic Institute Standards.

Ample experience with the same vendors and similar ECCS pumps has shown the variability in their NPSH requirements to be minimal. Pumps are deemed acceptable based on their vendor certified NPSH requirements being less than the maximum allowable specified by the ECCS designers. Although one specific pump may vary slightly from the certified curve, the curve is representative of all the pumps supplied and is always lower than the maximum available specified by the system designers. Furthermore, this number specified to the vendor is conservative compared to the ECCS layout criteria. The vendor supplied curve, which is used to confirm that the actual system piping provides adequate NPSH, is derived from repeated testing of the same type of pump. In addition to random testing to demonstrate that variation in pump performance is insignificant, each impeller casting is inspected to ensure that dissimilarity from one pump to the next is minimized.

For the RHR pump NPSH calculation, when taking suction from the containment sump, in equilibrium with containment ambient pressure (i.e., no credit is taken for subcooling of the sump fluid), the equation is:

$$NPSH_{available} = h_{static\ head} - h_{line\ losses}$$

For other system pumps, or for RHR pump NPSH when operating in other modes, this equation becomes:

$$NPSH_{available} = h_{ambient\ pressure} + h_{static\ head} - h_{line\ losses} - h_{vapor\ pressure}$$

The NPSH of the RHR pumps is evaluated for normal plant cooldown operation and for both the injection and recirculation modes of operation for the DBA. Recirculation operation gives the limiting

NPSH requirement, and the NPSH available is determined from the containment water level relative to the pump elevation and the pressure drop in the suction piping from the sump to the pumps. Positive NPSH margin is maintained with a postulated debris bed on the recirculation sump screens.

Centrifugal Charging Pumps

In the event of an accident, the charging pumps are started automatically on receipt of an “S” signal and are automatically aligned to take suction from the RWST during injection. During recirculation, suction is provided from the RHR pump discharge.

NPSH design considerations for the charging pumps are similar to those for the RHR pumps. The NPSH for the centrifugal charging pumps is evaluated for both the injection and recirculation modes of operation for the DBA.

Conclusion

The analysis for CSS Pumps is the same as the analysis presented in the RHR Pump section. The Centrifugal Charging Pump section also references the RHR analysis. The RHR Pump section provides the rationale, the formulae and parameters, but the conclusion is explicitly stated in the CSS Pump section, “no reliance is placed on the containment pressure for meeting the NPSH requirements.”

#### 3.1.3 Relief Request I3R-18, Regarding Alternative Repair and Replacement Testing Requirements for the Containment Building Equipment Hatch Sleeve Weld, Inservice Inspection Program for Containment, Third Ten-Year Interval

By letter dated June 4, 2018, Duke Energy Progress, LLC, submitted a request proposing an alternative to the requirements in 10 CFR 50.55a(g)(4) with regard to the post repair pressure testing requirements of the ASME B&PV Code, Section XI, 2007 Edition with 2008 Addenda, IWE-5000, as conditioned by 10 CFR 50.55a(b)(2)(ix)(J) (Reference 15).

HNP is replacing the reactor pressure vessel head during the fall refueling outage of 2019. The existing 15-ft. diameter bolted cover in the equipment hatch is not large enough to allow passage of the original reactor pressure vessel head or the replacement reactor pressure vessel head. The 24-ft. diameter body ring welds to a 24-ft. diameter penetration steel sleeve that penetrates the containment. HNP will cut the 24-ft. diameter portion of the steel sleeve outside the containment wall to facilitate the movement of the old and new reactor vessel heads through the 24-ft. opening created through the containment wall. Following completion of the reactor head replacement, the equipment hatch body ring will be re-welded to the penetration sleeve with a full penetration weld to restore the Containment Building equipment hatch to its original design configuration.

In relief request (RR) I3R-18, HNP proposed an alternative to the requirements in 10 CFR 50.55a(g)(4) with regard to the post-repair pressure testing requirements of the ASME B&PV Code, Section XI, 2007 Edition with 2008 Addenda, IWE-5000, as conditioned by 10 CFR 50.55a(b)(2)(ix)(J). Since the repair intends to restore the equipment hatch body ring weld to the containment penetration sleeve in accordance with ASME Code requirements, HNP suggested that an effective post-repair test of the equipment hatch weld's leak-tight integrity can be performed by an alternate leakage test, which pressurizes only the area affected by the reinstallation weld.

The requested duration of the proposed alternative is a one-time alternative for the ASME Code repair and replacement activity associated with the Containment Building equipment hatch and shall be acceptable for the life of the plant, or until such time that a future repair and replacement activity of this nature is performed again, whichever comes first. The reactor vessel head replacement activity associated with this proposed alternative is occurring during the fall refueling outage of 2019.

The re-welding activity represents the second removal and re-welding activity of the equipment hatch since its original installation. The first removal and rewelding activity was successfully performed by HNP in 2001 during the SGR project. Per letter dated February 26, 2019 (Reference 16), the NRC staff found the proposed re-welding activity acceptable because sufficient material exists in accordance with the HNP design specification to allow a second re-welding activity of the equipment hatch. The re-welding activity represents the second of the six re-welding activities for which this component was designed.

Once the equipment hatch is reinstalled, HNP proposed to perform a post-weld examination on the equipment hatch repair, which will include 100-percent radiographic examination of the weld and 100-percent magnetic particle testing of the weld to demonstrate 100-percent volumetric weld integrity. ASME Section III, Subsection NE requires all welds to be examined in accordance with the requirements of NE-5000 by qualified personnel. The NRC staff found the examination proposed by HNP acceptable because the proposed examination is in accordance with the ASME Section III, Subsection NE, requirements and acceptance criteria to ensure weld integrity of the reinstalled component.

As described in I3R-18, the repair and replacement activities associated with the temporary removal of the equipment hatch body and its reinstallation will be performed in accordance with the requirements of the 2007 Edition with 2008 Addenda of ASME Section XI, paragraph IWA-4411, which states that welding and installation activities shall be performed in accordance with the owner's requirements and in accordance with the construction code. The NRC staff found that HNP has met this requirement because the equipment hatch will be restored to its original design configuration by performing all fabrication and installation activities using the original construction code of ASME Section III, Subsection NE, or as reconciled to a later edition, and by meeting the HNP original design specifications and licensing basis to ensure structural integrity of the reinstalled weld.

Based on the above, the NRC staff determined that the proposed re-welding activity and post-weld examinations in accordance with referenced Code requirements and design specifications should ensure adequate structural weld integrity.

Per the RR, once the equipment hatch body ring has been re-welded to the existing penetration sleeve, a leakage test in accordance with ASME Code, Section XI, 2007 Edition with 2008 Addenda, IWE-5223, as modified by 10 CFR 50.55a, Paragraph (b)(2)(ix)(J) would be required. Whereas IWE-5223.2 allows limiting the test boundary to the area impacted by the repair/replacement activity, 10 CFR 50.55a(b)(2)(ix)(J) requires an ILRT (also referenced as a Type A test in 10 CFR 50, Appendix J) as the modification meets the definition of a major modification provided therein (i.e., "...cutting a large construction opening in the containment pressure boundary to replace steam generators, reactor vessel heads, ..."). The RR stated that an effective post-repair test of the equipment hatch weld's leak tight integrity could be performed by an alternate leakage test, which pressurizes only the area affected by the reinstallation weld.

In lieu of the post-repair 10 CFR Part 50, Appendix J, Type A test, the RR proposed a localized leakage test on the equipment body ring to the containment sleeve reinstallation weld area. A leak chase channel will be welded over the equipment channel reinstallation weld with a screwed half coupling to allow pressurization of the reinstallation weld area. The relief request provided the basis, features, and slight variations of the test as follows:

> ASME Code, Section XI, 2007 Edition with 2008 Addenda, IWE-5221(a) states that a pneumatic test shall be performed in accordance with IWE-5223 following repair/replacement activities performed by welding and brazing prior to returning the component to service. ASME Code, Section XI, 2007 Edition with 2008 Addenda, IWE-5223 states:
>
> > IWE-5223.1 Pressure. The pneumatic leakage test shall be conducted at a pressure between 0.96 $P_a$ and 1.10 $P_a$, except when otherwise limited by plant technical specifications, where $P_a$ is design basis accident pressure.
>
> According to TS 6.8.4.k, Pa for HNP is 41.8 psig, thus 1.10 $P_a$ is approximately 45.6 psig. However, HNP prefers to perform the test at a higher pressure of 51.8 psig due to a desire to conform to the original design specification. Excerpts from the original design specification were provided in Enclosure 2 to the relief request. The basis for the higher pressure of 51.8 psig is 1.15 x $P_d$, where $P_d$ is the design pressure of 45 psig. The NRC staff found this variance from IWE-5223.1 acceptable because it is a local test for the welds in the restored area of the hatch, and the equipment supplier previously subjected the hatch to the higher pressure.
>
> > IWE-5223.2 Boundaries. The test boundary may be limited to brazed joints and welds affected by the repair/replacement activity.
>
> The proposed test conforms to this requirement.
>
> > IWE-5223.4 Examination. During the pneumatic leakage test, the leak-tightness of the brazed joints and welds affected by the repair/replacement activity shall be verified by performing a bubble test described as a direct pressure technique in accordance with Section V, Article 10, Appendix I, or other Section V, Article 10 leak test that can be performed in conjunction with

the pneumatic test. An alternative to the bubble test can be a Type A, B, or C test, as applicable, in accordance with 10 CFR 50, Appendix J.

The licensee is proposing to perform a bubble test. The bubble test will also satisfy the equipment supplier requirement to perform solution film testing. The pressure applied during the test will be 51.8 psig. If leakage occurs, the weld will be repaired and retested. Thus, the acceptance criteria for the local leakage will essentially ensure zero leakage at the weld area.

The NRC staff also considered HNP's previous experience with the proposed test as part of the testing performed during the 2001 SGR project, where the equipment hatch was removed and reinstalled. However, a post-modification ILRT was not a requirement at that time. HNP stated that the test configuration used in 2001 is similar to the test configuration proposed in the relief request. HNP also stated that a Type A ILRT was performed in 2012, with no issues identified with leakage at the equipment hatch circumferential weld. The test results were found acceptable with approximately 42-percent margin remaining.

The NRC staff has determined that, from a containment leakage testing perspective, the proposed test is in accordance with referenced Code requirements and is functionally equivalent to the Type A test. The local leak rate test (LLRT) proposed by the relief request should ensure essentially no leakage through the tested re-attachment weld area. The re-attachment weld will be subsequently tested as part of the periodic Type A tests.

The NRC staff determined that the proposed alternative provided an acceptable level of quality and safety and concluded that the licensee adequately addressed all of the regulatory requirements set forth in 10 CFR 50.55a(z)(1) and is in compliance with the ASME Code requirements. Therefore, the NRC staff authorized the use of the proposed alternative in RR I3R-18 for the one-time reactor vessel head replacement activity scheduled for the fall of 2019 refueling outage at HNP (Reference 16).

## 3.2 JUSTIFICATION FOR THE TECHNICAL SPECIFICATION CHANGE

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

The testing requirements of 10 CFR 50, Appendix J, provide assurance that leakage from the containment, including systems and components that penetrate the containment, does not exceed the allowable leakage values specified in the TS. 10 CFR 50, Appendix J also ensures that periodic surveillances of reactor containment penetrations and isolation valves are performed so that proper maintenance and repairs are made during the service life of the containment and of 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 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

CIV leakage rates. Type B and C tests identify the vast majority of potential containment leakage paths. Type A tests identify the overall (i.e., 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 Type B and C testing.

In 1995, 10 CFR 50, Appendix J, 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 6) and Electric Power Research Institute (EPRI) TR-104285 (Reference 7), 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 extension of interval “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 8), 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 (SE) report (SER) on NEI 94-01. 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 (Reference 1). The document also 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 by RG 1.163 and NRC SERs dated June 25, 2008 (Reference 9), and June 8, 2012 (Reference 10), as an acceptable methodology for complying with the provisions of Option B in 10 CFR 50, Appendix J. The regulatory positions stated in RG 1.163, as modified by References 9 and 10, are incorporated in this document. It delineates a performance-based approach for determining Type A, Type B, and Type C containment leakage rate surveillance testing frequencies. Justification for extending test intervals is based on the performance history and risk insights.

Extensions of Types B and 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 air locks) 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 (Reference 2).

The NRC has provided guidance concerning the use of test interval extensions in the deferral of ILRTs beyond the 15-year interval in NEI 94-01, Revision 2-A, NRC SER Section 3.1.1.2 (Reference 9):

> 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 percent 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 BWR MSIVs [main steam isolation valves]) 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, Item 2 (Reference 10):

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 HNP CLRT 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. HNP has implemented the requirements of 10 CFR 50, Appendix J, Option A for Types B and C testing and Option B for Type A testing. Current TS 6.8.4.k requires the following:

This program shall be in conformance with the NRC Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995, with the following exceptions noted:

1) The above Containment Leakage Rate Testing Program is only applicable to Type A testing. Type B and C testing shall continue to be conducted in accordance with the original commitment to 10 CFR 50 Appendix J, Option A.

2) The first Type A test performed after the May 23, 1997 Type A test shall be performed no later than May 23, 2012.

3) Visual examination of the containment system shall be in accordance with Specification 4.6.1.6.1.

Option B states that specific existing exemptions to Option A are still applicable unless specifically revoked by the NRC.

Currently, TS 6.8.4.k requires that a program be established to comply with the CLRT requirements of 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B for Type A testing and Option A for Type B and Type C testing, as modified by approved exemptions. The program is required to be in accordance with the guidelines contained in RG 1.163 with exceptions. 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 ANSI/ANS 56.8-1994. NEI 94-01, Section 11.0 refers to Section 9.0, 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 (2) consecutive periodic Type A tests where the calculated performance leakage rate was less than 1.0 $L_a$ (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 CLRT 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 (Reference 6). The evaluation documented in NUREG-1493 included a study of the dependence or reactor accident risks on containment leak tightness for differing containment types. NUREG-1493 concluded in Section 10.1.2 that reducing the frequency of Type A tests (ILRT) from the original three tests per 10 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 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, NUREG-1493 concluded that increasing the interval between ILRTs is possible with minimal impact on public risk.

### 3.2.3 HNP 10 CFR 50, Appendix J, Option B Licensing History

September 17, 1999 – License Amendment No. 91 (Reference 12)

The NRC issued Amendment No. 91 for HNP which revised the TS to incorporate the performance-based 10 CFR 50, Appendix J, Option B, for Type A containment ILRTs.

October 12, 2001 – License Amendment No. 107 (Reference 14)

The NRC issued Amendment No. 107 for HNP in response to the HNP LAR dated October 4, 2000, for the SGR and December 14, 2000, for a Power Uprate (PU).

The SGR application requested a license amendment that allows HNP operation with Westinghouse Model Delta 75 SGs. The PU application allowed HNP operation at a maximum power level of 2900 megawatts thermal (MWt), an approximate 4.5 percent increase from the previous licensed power of 2775 MWt.

This amendment also revised the accident analyses to adopt the alternate source term (AST) methodology, using the guidance of RG 1.183 (Reference 47).

In addition, this amendment changed $P_a$ for the purpose of containment testing in accordance with TS 6.8.4.k from 41.2 psig to 41.8 psig.

March 30, 2006 – License Amendment No. 122 (Reference 13)

The NRC issued Amendment No. 122 for HNP. The amendment revised TS 6.8.4.k, "Containment Leakage Rate Testing Program," and TS SR 4.6.1.6.1, "Containment Vessel Surfaces." Specifically, the amendment allows a one-time extension of the 10 CFR 50, Appendix J, Type A, Containment ILRT interval from once in 10 years to once in 15 years.

February 26, 2019 – Relief Request I3R-18 (Reference 16)

By letter dated June 4, 2018 (Reference 15), Duke Energy submitted a request for the use of alternatives to certain ASME B&PV Code, Section XI, 2007 Edition with 2008 Addenda requirements at HNP.

Specifically, pursuant to 10 CFR 50.55a(z)(1), HNP requested to use a proposed alternative on the basis that the alternative provides an acceptable level of quality and safety. HNP proposed to use a "bubble test-direct pressure technique" in accordance with the requirements of the ASME Code, Section V, Article 10, Appendix I, in lieu of the 10 CFR 50.55a requirement to perform a containment leak rate test. The NRC authorized the use of the proposed alternative in relief request I3R-18 for the one-time reactor vessel head replacement activity scheduled for the fall of 2019 refueling outage.

### 3.2.4 Integrated Leakage Rate Testing History

As noted previously, HNP TS 6.8.4.k currently requires Type A testing in accordance with RG 1.163, which endorses the methodology for complying with 10 CFR 50, Appendix J, 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.

Table 3.2.4-1 lists the past Periodic Type A ILRT results for HNP, Unit 1.

**Table 3.2.4-1, HNP Unit 1 ILRT Test History**

| Test Date | 95% Upper Confidence Limit % Containment Air Mass/Day |
|---|---|
| February 1986 - Preoperational | 0.05199[1] |
| October 1989 | 0.0406[1] |
| September 1992 | 0.0701[1] |
| May 1997 | 0.0265[2] |
| May 2012 | 0.0605[2] |

Note 1: As specified in HNP TS 6.8.4.k, the maximum allowable containment leakage rate $L_a$, at $P_a$ of 41.2 psig, is 0.1% of primary containment air weight per day (prior to Amendment No. 107).

Note 2: As specified in HNP TS 6.8.4.k, the maximum allowable containment leakage rate $L_a$, at $P_a$ of 41.8 psig, is 0.1% of primary containment air weight per day (reference Amendment No. 107 for SGR and PU).

The current ILRT test interval for HNP Unit 1 is ten years. Verification of this interval is presented in Table 3.2.4-2. The acceptance criteria used for this verification is contained in NEI 94-01, Revision 2-A and Revision 3-A, Section 5.0, Definitions, and is as follows:

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

**Table 3.2.4-2**
**Verification of Current Extended ILRT Interval for HNP**

| Test Date | Upper 95% Confidence Level (wt.%/day) (Test Pressure) | Level Corrections (wt.%/day) | As-Left Min Pathway Penalty for Isolated Pathways (wt.%/day) | Adjusted As-Left Leak Rate (wt.%/day) | ILRT Acceptance Criteria | Test Method / Data Analysis Techniques |
|---|---|---|---|---|---|---|
| May 1997 | 0.0265 (44.0 psig) | -0.0000 | 0.0004 | 0.0269 | 0.75 $L_a$ (0.075 weight %/day) | Absolute Method / Mass Point Analysis |
| May 2012 | 0.0605 (43.3 psig) | -0.0000 | 0.0008 | 0.0613 | 0.75 $L_a$ (0.075 weight %/day) | Absolute Method / Mass Point Analysis |

## 3.3 PLANT SPECIFIC CONFIRMATORY ANALYSIS

### 3.3.1 Methodology

An analysis was performed to provide a risk assessment of permanently extending the currently allowed containment Type A ILRT from ten years to fifteen years. The extension would allow for substantial cost savings as the ILRT could be deferred for additional scheduled refueling outages for HNP. The risk assessment follows the guidelines from NEI 94-01, Revision 3-A (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 19); the NRC regulatory guidance on the use of Probabilistic Risk Assessment (PRA) as stated in RG 1.200 (Reference 4) as applied to ILRT interval extensions; risk insights in support of a request for a plant's licensing basis as outlined in RG 1.174 (Reference 3); 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 40); and, the methodology used in EPRI 1018243, Revision 2-A of EPRI 1009325 (Reference 11).

Details of the HNP risk assessment, providing an assessment of the risk associated with implementing a permanent extension of the HNP Containment Type A ILRT interval from ten years to fifteen years, is contained in Attachment 3 of this submittal.

The basis for the current 10-year test interval is provided in Section 11.0 of NEI 94-01, Revision 0, and was established in 1995 during development of the performance-based Option B to Appendix J. Section 11.0 of NEI 94-01 (Reference 5) states that NUREG-1493 (Reference 6) provides the technical basis to support rulemaking to revise leakage rate testing requirements contained in Option B to Appendix J. The basis consisted of qualitative and quantitative assessment of the risk impact, in terms of increased public dose, associated with a range of extended leakage rate test intervals. To supplement the NRC's rulemaking basis, NEI undertook a similar study. The results of that study are documented in 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 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 HNP.

NEI 94-01, Revision 3-A supports using EPRI Report No. 1009325 Revision 2-A (EPRI 1018243), "Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals," for performing risk impact assessments in support of ILRT extensions (Reference 11). 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.

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 ASME B&PV Code, Section XI. More specifically, Subsection IWE provides the rules and requirements for inservice inspection of metal containment (Class MC) pressure-retaining components and their integral attachments, and of metallic shell and penetration liners of concrete containment (Class CC) pressure-retaining components and their integral attachments in light-water cooled plants. Furthermore, NRC regulation 10 CFR 50.55a(b)(2)(ix)(E) requires 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 LLRTs performed to verify the leak-tight integrity of containment penetration bellows, air locks, seals, and gaskets are also not affected by the change to the Type A test frequency.

In the NRC SE dated June 25, 2008 (Reference 9), the NRC concluded that the methodology in EPRI TR-1009325, Revision 2 (Reference 11), was acceptable for referencing by licensees proposing to amend their TS to permanently extend the ILRT surveillance interval to 15 years, subject to the limitations and conditions noted in Section 4.0 of the SE. Table 3.3.1-1 below addresses each of the four (4) limitations and conditions from Section 4.2 of the SE for the use of EPRI 1009325, Revision 2.

**Table 3.3.1-1**
**EPRI Report No. 1009325, Revision 2, Limitations and Conditions**

| Limitation and Condition (From Section 4.2 of SE) | HNP 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 application. | HNP PRA technical adequacy is addressed in Section 3.3.2 of this LAR and Attachment 3, "Shearon Harris Nuclear Power Plant: Evaluation of Risk Significance of Permanent ILRT Extension," Appendix A, "PRA Acceptability." |
| 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. | Because the ILRT does not impact core damage frequency (CDF), the relevant criterion is large early release frequency (LERF). The increase in LERF resulting from a change in the Type A ILRT test interval from 3-in-10 years to 1-in-15 years is estimated as 6.52E-8/year using the EPRI guidance; this value increases negligibly if it includes the risk impact of corrosion-induced leakage of the steel liners occurring and going undetected during the extended test interval. Therefore, the estimated change in LERF is determined to be "very small" using the acceptance guidelines of RG 1.174.<br><br>When external event risk is included, the increase in LERF resulting from a change in the Type A ILRT test interval from 3-in-10 years to 1-in-15 years is estimated as 4.57E-7/year using the EPRI guidance, and total LERF is 5.46E-6/year. As such, the estimated change in LERF is determined to be "small" using the acceptance guidelines of RG |

**Table 3.3.1-1**
**EPRI Report No. 1009325, Revision 2, Limitations and Conditions**

| Limitation and Condition (From Section 4.2 of SE) | HNP Response |
|---|---|
| | 1.174. (See Attachment 3, 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 effect resulting from changing the Type A test frequency to 1-per-15 years, measured as an increase to the total integrated plant risk for those accident sequences influenced by Type A testing, is 0.038 person-rem/year. NEI 94-01 (Reference 2) states that a small population dose is defined as an increase of ≤ 1.0 person-rem per year, or ≤ 1% of the total population dose, whichever is less restrictive for the risk impact assessment of the extended ILRT intervals. The results of this calculation meet these criteria. Moreover, the risk impact for the ILRT extension when compared to other severe accident risks is negligible. (See Attachment 3, 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 (CCFP) from the 3-in-10 years interval to 1-in-15 years interval is 0.753%. NEI 94-01 states that an increase in CCFP of ≤ 1.5% is small. Therefore, this increase is judged to be small. (See Attachment 3, Section 7.0 of this submittal.) |
| 3. The methodology in EPRI Report No. 1009325, Revision 2, is acceptable except for the calculation of the increase in expected population dose (per year of reactor operation). In order to make the methodology acceptable, the average leak rate for the pre-existing containment large 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 HNP is 100 $L_a$, based on the guidance provided in EPRI Report No. 1009325, Revision 2-A. (See Attachment 3, Section 4.0 of this submittal.) |
| 4. A LAR is required in instances where containment over-pressure is relied upon for ECCS performance. | HNP does not rely upon containment over-pressure for ECCS performance. (Refer to Section 3.1.2 of this submittal.) |

### 3.3.2 PRA Acceptability

A PRA analysis was utilized to support an extension of the HNP ILRT test interval from ten years to fifteen years.

PRA Quality Statement for Permanent 15-Year ILRT Extension

The Duke Energy risk management process ensures that the applicable PRA models used in this application continue to reflect the as-built and as-operated plant for HNP. The process delineates the responsibilities and guidelines for updating the PRA models, and includes criteria for both regularly scheduled and interim PRA model updates. The process includes provisions for monitoring potential areas affecting the PRA models (e.g., due to changes in the plant, errors or limitations identified in the model, industry operational experience) for assessing the risk impact of unincorporated changes, and for controlling the model and associated computer files. The process will assess the impact of these changes on the plant PRA model in a timely manner but no longer than once every two refueling outages.

HNP has full-power internal events, internal floods, and fire PRA models. The HNP models are highly detailed and include a wide variety of initiating events, modeled systems, operator actions, and common cause events. The PRA quantification process used is based on the large linked fault tree methodology, which is a well-known and accepted methodology in the industry. The models are maintained and quantified using the EPRI Risk & Reliability suite of software programs.

The following sections describe the specific peer review history, results, and open facts and observations (F&Os) associated with each PRA model used in this analysis. The Type A test surveillance frequency change PRA analysis is judged to meet the technical adequacy requirements for the application.

Internal Events and Internal Flooding PRA

The HNP internal events PRA model was subject to a self-assessment and a full-scope peer review conducted in 2002 in accordance with guidance in NEI-00-02, Industry PRA Peer Review Process. In 2006, a self-assessment was conducted to identify supporting requirements that did not meet Category II of the ASME Standard RA-Sb-2005 and RG 1.200 Revision 1. In 2007, a focused scope industry peer review against two elements was conducted as a follow-up to the self-assessment against ASME Standard RA-Sb-2005 and RG 1.200 Revision 1. In July 2017, a focused scope industry peer review was conducted against one model area that was upgraded.

The Internal Events PRA (IEPRA) model was peer reviewed in 2002 by the PWR Owners Group (PWROG) prior to the issuance of RG 1.200. As a result, Duke Energy conducted self-assessments of the IEPRA model in accordance with Appendix B of RG 1.200, Revision 2 (Reference 4) to address the PRA technical adequacy requirements not considered in the 2002 peer review. The NRC previously reviewed the IEPRA technical adequacy (including the 2002 peer review and self-assessment results) in previous LARs noted below:

- License Amendment Regarding Risk-Informed Justifications for the Relocation of Specific Surveillance Frequency Requirements to a Licensee-Controlled Program, November 29, 2016 (Reference 36).
- License Amendment Regarding Adoption of National Fire Protection Association Standard 805, June 28, 2010 (Reference 37).
- License Amendment Regarding Adoption of 10 CFR 50.69, “Risk-Informed Categorization and Treatment of Structures, Systems, and Components (SSCs) for Nuclear Power Reactors,” September 17, 2019 (Reference 45)

Upgrades that have occurred since the PWROG peer review in 2002 have been reviewed in accordance with the peer review process. There are no unreviewed PRA upgrades as defined by the ASME PRA Standard RA-Sa-2009 (Reference 25) in the IEPRA model.

The HNP internal flood PRA model was subject to a self-assessment and a full-scope (covering all internal flood SRs) peer review conducted in August 2014 against RG 1.200, Revision 2.

Closed findings were reviewed and closed in March 2017 for the IEPRA and Internal Flood models as a pilot for the process documented in the draft of Appendix X to NEI 05-04, NEI 07-12, and NEI 12-13, “Close-out of Facts and Observations,” published at the time of the review. NRC staff observed the pilot closure on-site event held January 31 through February 1, 2017. An assessment has been performed to determine the impact of changes to the guidance between the closure event and the final version endorsed by NRC. The main deltas identified are related to: 1) utility and review team’s documented determination and justification if each finding resolution is an upgrade verses maintenance update, and 2) the assessment team’s confirmation that for the closed F&Os, the aspects of the underlying SRs in ASME/ANS RA-Sa-2009 that were previously not met, or met at capability category I (CC-I), are now met or met at capability category II (CC-II). The utility portion of the upgrade versus maintenance assessment was completed globally and did not identify any resolutions as an upgrade. Additionally, the review team determined none of the resolutions were upgrades and this is documented in the final report. The assessment team confirmed resolution of the findings allowed re-categorization of capability categories to meet or met at CC-II, as applicable. The results of this review have been documented and are available for NRC audit.

There are no open findings for the HNP IEPRA model. Ten Internal Flooding PRA F&Os remain open and are dispositioned in Attachment 3, Section A.2 of this submittal. All the Finding Level F&Os have been determined to not significantly affect the ILRT extension analysis.

<u>Fire PRA</u>

The HNP Fire PRA model was subject to a review conducted by the NRC during the NFPA 805 Pilot process and an additional focused scope industry peer review, both in 2008 in accordance with

ANSI/ANS-58.23-2007. Since the reviews of the Fire PRA model were performed prior to the publication of RG 1.200, Revision 2, a self-assessment was conducted to assess the differences between ANSI/ANS-58.23-2007 and the current version of the PRA standard, ASME/ANS RA-Sa-2009. That assessment confirmed there were no technical differences between the two versions of the standard.

Findings were reviewed and closed in October 2017 for the Fire PRA model using the process documented in Appendix X to NEI 05-04, NEI 07-12 and NEI 12-13, "Close-out of Facts and Observations," as accepted by the NRC in the letter dated May 3, 2017 (Reference 42). The results of this review have been documented and are available for NRC audit.

HNP has since updated the analysis to include the risk assessment of fires impacting structural steel members and the incorporation of obstructed plume model into selected fire scenarios associated with electrical cabinets. These updates required a focused scope peer review, which was conducted in June 2019 (Reference 41). Two findings were identified during the focused-scope peer review, which were subsequently closed during an F&O independent assessment (Reference 43).

Four Fire PRA F&Os remain open and are dispositioned in Attachment 3, Section A.3 of this submittal. All the Finding Level F&Os have been determined to not significantly affect the ILRT extension analysis.

### 3.3.3 Summary of Plant-Specific Risk Assessment Results

The findings of the HNP Risk Assessment contained in Attachment 3 confirm the general findings of previous studies that the risk impact associated with extending the ILRT interval from three-in-ten years to 1-in-15 years is small.

Based on the results from Attachment 3, Section 5.2 and the sensitivity calculations presented in Attachment 3, Section 5.3 of this submittal, the following conclusions regarding the assessment of the plant risk are associated with extending the Type A ILRT test frequency to 15 years:

- RG 1.174 (Reference 3) provides guidance for determining the risk impact of plant-specific changes to the licensing basis. RG 1.174 defines very small changes in risk as resulting in increases of CDF less than 1.0E-06/year and increases in LERF less than 1.0E-07/year. Since the ILRT does not impact CDF, the relevant criterion is LERF. The increase in LERF resulting from a change in the Type A ILRT test interval from 3-in-10 years to 1-in-15 years is estimated as 6.52E-8/year using the EPRI guidance; this value increases negligibly if it includes the risk impact of corrosion-induced leakage of the steel liners occurring and going undetected during the extended test interval. Therefore, the estimated change in LERF is determined to be "very small" using the acceptance guidelines of RG 1.174. The risk change resulting from a change in the Type A ILRT test interval from 3-in-10 years to 1-in-15 years bounds the 1-in-10 years to 1-in-15 years risk change. Considering the increase in LERF resulting from a change in the Type A ILRT test interval from 1-in-10 years to 1-in-15 years is estimated as 2.72E-8, the risk increase is "very small" using the acceptance guidelines of RG 1.174.

- When external event risk is included, the increase in LERF resulting from a change in the Type A ILRT test interval from 3-in-10 years to 1-in-15 years is estimated as 4.57E-7/year using the EPRI guidance, and total LERF is 5.46E-6/year. As such, the estimated change in LERF is determined to be "small" using the acceptance guidelines of RG 1.174. The risk change resulting from a change in the Type A ILRT test interval from 3-in-10 years to 1-in-15 years bounds the 1-in-10 years to 1-in-15 years risk change. When external event risk is included, the increase in LERF resulting from a change in the Type A ILRT test interval from 1-in-10 years to 1-in-15 years is estimated as 1.91E-7 and the total LERF is 5.20E-6. Therefore, the risk increase is "small" using the acceptance guidelines of RG 1.174.

- The effect resulting from changing the Type A test frequency to 1-per-15 years, measured as an increase to the total integrated plant risk for those accident sequences influenced by Type A testing, is 0.038 person-rem/year. NEI 94-01 (Reference 2) states that a small population dose is defined as an increase of ≤ 1.0 person-rem per year, or ≤ 1% of the total population dose, whichever is less restrictive for the risk impact assessment of the extended ILRT intervals. The results of this calculation meet these criteria. Moreover, the risk impact for the ILRT extension when compared to other severe accident risks is negligible.

- The increase in the CCFP from the 3-in-10 years interval to 1-in-15 years interval is 0.753%. NEI 94-01 states that an increase in CCFP of ≤ 1.5% is small. Therefore, this increase is judged to be small.

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

### 3.3.4 Previous Assessments

The NRC in NUREG-1493 (Reference 6) previously concluded that:

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

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

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

Details of the HNP risk assessment are contained in Attachment 3 of this LAR submittal.

### 3.3.5 RG 1.174 Revision 3 Defense-in-Depth Evaluation

RG 1.174, Revision 3 (Reference 39) describes an approach that is acceptable for developing risk-informed applications for a licensing basis change that considers engineering and applies risk insights. One of the considerations included in RG 1.174 is defense in depth. Defense in depth is a safety philosophy that employs successive compensatory measures to prevent accidents or mitigate damage if a malfunction, accident, or naturally caused event occurs at a nuclear facility. The following seven considerations as presented in RG 1.174, Revision 3, Section 2.1.1.2 will serve to evaluate the proposed licensing basis change for overall impact on defense in depth.

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

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

<u>Response</u>:
Several layers of defense are in place to ensure the HNP containment structure penetrations, isolation valves, and mechanical seal systems continue to perform their intended safety functions. The purpose of the proposed change is to extend the testing frequencies of the Type A ILRT from 10 years to 15 years and Type C LLRTs for selected components from 60 months to 75 months.

As shown in NUREG-1493 (Reference 6), increasing the test frequency of ILRTs up to a 20-year test interval was found to lead to an imperceptible increase in risk. The estimated increase in risk is very small because ILRTs identify only a few potential containment leakage paths that cannot be identified by Type B or Type C testing. The study also concluded that extending the frequency of Type B tests is possible with no adverse impact on risk as identified leakage through Type B mechanical penetrations are both infrequent and small. Finally, the study concluded that Types B and C tests could identify the vast majority (i.e., greater than 95 percent) of all potential leakage paths.

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

<u>PRA Response</u>:
The use of the risk metrics of LERF, population dose, and CCFP collectively ensures the balance between prevention of core damage, prevention of containment failure, and consequence mitigation is preserved. The change in LERF is “very small” with respect to internal events and “small” when including external events per RG 1.174, and the change in population dose and CCFP are “small” as defined in this analysis and consistent with NEI 94-01, Revision 3-A.

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

Nuclear power plant licensees implement a number of programmatic activities, including programs for quality assurance, testing and inspection, maintenance, control of transient combustible material, foreign material exclusion, containment cleanliness, and training. In some cases, activities that are part of these programs are used as compensatory measures; that is, they are measures taken to compensate for some reduced functionality, availability, reliability, redundancy, or other feature of the plant’s design to ensure safety functions (e.g., reactor vessel inspections that provide assurance that reactor vessel failure is unlikely). NUREG-2122, “Glossary of Risk-Related Terms in Support of Risk-Informed Decision Making,” (Reference 38), defines “safety function” as those functions needed to shut down the reactor, remove the residual heat, and contain any radioactive material release.

A proposed licensing basis change might involve or require compensatory measures. Examples include hardware (e.g., skid-mounted temporary power supplies); human actions (e.g., manual system actuation); or some combination of these measures. Such compensatory measures are often associated with temporary plant configurations. The preferred approach for accomplishing safety functions is through engineered systems. Therefore, when the proposed licensing basis change necessitates reliance on programmatic activities as compensatory measures, the licensee should justify that this reliance is not excessive (i.e., not overly reliant). The intent of this consideration is not to preclude the use of such programs as compensatory measures but to ensure that the use of such measures does not significantly reduce the capability of the design features (e.g., hardware).

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

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

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

As stated in RG1.174, Revision 3, Section C.2.1.1.1 , the defense-in-depth philosophy has traditionally been applied in plant design and operation to provide multiple means to accomplish safety functions.

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

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

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

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

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

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

**4. Preserve adequate defense against potential CCFs.**

An important aspect of ensuring defense in depth is to guard against CCF. Multiple components may fail to function because of a single specific cause or event that could simultaneously affect several components important to risk. The cause or event may include an installation or construction deficiency, accidental human action, extreme external environment, or an unintended cascading effect from any other operation or failure within the plant. CCFs can also result from poor design, manufacturing, or maintenance practices.

Defenses can prevent the occurrence of failures from the causes and events that could allow simultaneous multiple component failures. Another aspect of guarding against CCF is to ensure that an existing defense put in place to minimize the impact of CCF is not significantly reduced; however, a reduction in one defense can be compensated for by adding another.

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

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

**5. Maintain multiple fission product barriers.**

Fission product barriers include the physical barriers themselves (e.g., the fuel cladding, RCS pressure boundary, and containment) and any equipment relied on to protect the barriers (e.g., CS).

In general, these barriers are designed to perform independently so that a complete failure of one barrier does not disable the next subsequent barrier. For example, one barrier, the containment, is designed to withstand a double-ended guillotine break of the largest pipe in the RCS, another barrier.

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

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

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

**6. Preserve sufficient defense against human errors.**

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

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

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

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

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

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

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

Conclusion:

The responses to the seven defense-in-depth considerations above conclude that the existing defense in depth has not been diminished, but rather increased in some instances. Therefore, the proposed change does not comprise a reduction in safety.

## 3.4 NON-RISK BASED ASSESSMENT

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

### 3.4.1 Nuclear Coatings Program

The HNP Protective Coatings Program establishes guidelines for the maintenance of protective coatings that are applied to existing concrete and steel surfaces within Service Level I, II, III, and Balance of Plant (BOP) areas.

Service Level I (SL1) – Coatings applied to structures, systems, and components, which are or will be located inside primary containment and subject to DBA conditions. These coatings shall be a qualified coatings system.

A condition assessment of SL1 protective coatings shall be performed during every refueling outage. This coatings maintenance walkdown shall include a visual inspection of a sample of coated steel and concrete surfaces at different locations and a sample of areas/ components identified in the Coatings Exempt Logs.

Protective coatings on the Containment Building liner, exterior wall, and other steel and associated concrete surfaces will be periodically inspected under the site IWE/IWL, Containment Inspection Program.

Unqualified coatings in the Containment Building are tracked by an exempt or unqualified coatings log and are periodically inspected to ensure that no degradation has occurred.

Unqualified coatings that are identified for addition to the Coatings Exempt Log, Unqualified Coatings Log, or Unqualified Vendor Coatings Exempt Log, shall also be evaluated against the maximum allowable quantity of unqualified coatings.

Revisions to the Coatings Exempt Logs shall be made prior to the end of any Refueling Outage where log entries or deletions are initiated and approved.

**Containment Unqualified Coatings Log**

The purpose of the Containment Unqualified Coatings Log (calculation) is to evaluate the quantity of “unqualified” protective coatings in the HNP Containment Building and to ensure that this documented quantity does not exceed postulated design limits. This calculation contains the “unqualified” protective coatings exempt log that was initiated in 1985 and will also document and approve additions and deletions that are made to this log during current plant refueling outages.

HNP routinely conducts condition assessment walkdowns of both qualified and unqualified protective coatings inside the containment. These coating condition assessments are conducted as part of HNP’s periodic maintenance program that requires a coating assessment walkdown every refueling outage. Typically, these Containment walkdowns encompass 100% inspections of all concrete and steel surfaces by elevation. Any localized areas of degraded coatings identified are evaluated and scheduled for repair or recoating as necessary. These periodic condition assessments and any resulting repair or recoating activities help ensure that the amount of containment protective coatings susceptible to detachment during a LOCA is minimized.

ANSI N101.4 and ANSI N101.2 are endorsed by the NRC in RG 1.54 (Reference 28) as a means of complying with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” for safety-related protective coating applications. Safety-related protective coatings can be exposed to various environmental conditions inside containment. Protective coatings are qualified by testing for the environmental conditions expected during the enveloping DBA as described in corporate specifications. The environmental conditions used to determine qualification are temperature, pressure, and radiation dose. The regulatory requirement for protective coating material qualification is based on RG 1.54. Protective coatings meeting these requirements will not form loose debris (by detachment from their substrate) inside containment and are described as Qualified Coatings. Protective coatings that do not meet these requirements or exhibit evidence of degradation, such as their ability to adhere to the substrate is questionable, are called unqualified coatings. If coatings should become detached, these unqualified coatings are considered debris that can block ECCS flow. The quantity and characteristics of debris that could be generated during a LOCA inside the Containment Building are determined via an HNP calculation. This calculation sets the debris loading limit, due to detachment of unqualified coatings inside the containment, at 10,000 square ft. ($ft^2$). To ensure that protective coatings inside containment perform their design basis function, the amount of protective coating debris should be less than the design basis limiting value. Condition monitoring inspections are performed each refueling outage to assure the total quantity of unqualified coatings are below this limit.

2016 Refueling Outage Unqualified Coatings Quantity Summary:
The total quantity of unqualified coatings following the 2015 refueling outage was as follows:

SL1 Coatings Exempt Log: Total = 9,000.58 $ft^2$ of 10,000 $ft^2$ Limit
Unqualified Vendor Coatings Exempt Log: Total = 4180.52 $ft^2$ of 4350 $ft^2$ Limit

With completion of the Condition Monitoring Walkdown for the 2016 refueling outage, the total quantity of unqualified coatings was as follows:

9000.58 $ft^2$ + 28.30 $ft^2$ – 4.28 $ft^2$ = 9024.60 $ft^2$
4180.52 ft2 + 28.30 $ft^2$ – 4.28 $ft^2$ = 4204.54 $ft^2$

SL1 Coatings Exempt Log: Total = 9024.6 $ft^2$ of 10,000 $ft^2$ Limit (90.25%)
Unqualified Vendor Coatings Exempt Log: Total = 4204.5 $ft^2$ of 4350 $ft^2$ Limit (96.7%)

2018 Refueling Outage Unqualified Coatings Quantity Summary:
The total quantity of unqualified coatings following the 2016 refueling outage was as follows:

SL1 Coatings Exempt Log: Total = 9024.6 $ft^2$ of 10,000 $ft^2$ Limit
Unqualified Vendor Coatings Exempt Log: Total = 4204.5 $ft^2$ of 4350 $ft^2$ Limit

With completion of the Condition Monitoring Walkdown for the 2018 refueling outage, the total quantity of unqualified coatings was unchanged from the 2016 refeuling outage:

SL1 Coatings Exempt Log: Total = 9024.6 $ft^2$ of 10,000 $ft^2$ Limit (90.25%)
Unqualified Vendor Coatings Exempt Log: Total = 4204.5 $ft^2$ of 4350 $ft^2$ Limit (96.7%)

### 3.4.2 Containment Inservice Inspection (CISI) Program

**Scope**

The scope of this plan details the ISI Plan for HNP for the 4$^{th}$ Ten-Year ISI Interval Program and the 3$^{rd}$ Ten-Year CISI Interval Containment Programs.

The Inservice Inspection Examination Plan (ISI Plan) provides requirements for examination, testing, and inspection of Class 1, 2, 3, MC, and Concrete Containment (CC) components and systems, and their supports.

The scope of this plan does not include the Pressure Testing ISI Program, Augmented ISI Program, Appendix J Program, Inservice Testing of Pumps and Valves (IST), Snubber Functional Testing Program, or Steam Generator Tubing Program.

**Purpose**

The ISI Plan and schedule documents implement the requirements of ASME Code Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," subsections IWA, B, C, D, E, F, and L, in accordance with 10 CFR 50.55a.

In accordance with the requirements of 10 CFR 50.55a(g)(4)(ii) (82 FR 32934, July 18, 2017), the inservice inspection of HNP shall be performed in accordance with the 2007 Edition of ASME Section XI, through the 2008 Addenda, hereafter referred to as Section XI, subject to conditions specified in 10 CFR 50.55a(b)(2).

**License Renewal**

The CISI Plans are credited in the HNP license renewal as described in the NRC SER (Reference 21). The following are credited with managing component and system degradation in accordance with the NRC SER:

- ASME Section XI, Subsection IWE Program
- ASME Section XI, Subsection IWL Program

**Plan History**

CISI examinations were originally invoked by amended regulations contained within a Final Rule issued by the NRC. The amended regulation incorporated the requirements of the 1992 Edition through the 1992 Addenda of the ASME Section XI, Subsections IWE and IWL, subject to specific modifications that were included in 10 CFR 50.55a(b)(2). The first CISI interval for HNP was effective from September 9, 1998, through September 8, 2008. As allowed by IWA-2430(c)(1), a one-year extension was taken for the first CISI interval until September 8, 2009. This extension did not affect the start of the second CISI interval. HNP extended the first CISI interval in order to complete the first CISI interval examinations. The second HNP CISI interval began on September 9, 2008, and was effective through September 8, 2018.

The third CISI interval began on May 20, 2018. Based on this date, the latest edition and addenda of ASME Section XI referenced in 10 CFR 50.55a(b)(2) is the 2007 Edition through the 2008 Addenda. The HNP third CISI interval will be effective from May 20, 2018, through September 8, 2027. The start date for the third CISI interval was adjusted in accordance with IWA-2430(c)(1).

During the third CISI interval, the interval end date may be extended to no later than May 20, 2029 (11 years following the third interval start date of May 20, 2018), and shall not end prior to September 8, 2027 (12 months prior to the original pattern of intervals that would have ended on September 8, 2028). Because of this, the subsequent CISI (fourth) interval may start no earlier than September 9, 2027, and must start no later than the end of the third CISI interval.

Dates for intervals and periods for CISI examinations are as indicated in Tables 3.4.2-1 and 3.4.2-2 for Class MC components and Tables 3.4.2-3 and 3.4.2-4 for Class CC components.

| **Table 3.4.2-1, THIRD CISI INTERVAL/PERIOD/OUTAGE MATRIX (FOR CISI CLASS MC COMPONENT EXAMINATIONS – IWE Only)** | | | |
|---|---|---|---|
| **Interval** | **Period** | **Outages** | |
| **Start Date to End Date** | **Start Date to End Date** | **Outage Dates During Inspection Period** | **Outage Number** |
| 3rd 05/20/2018 to 09/08/2027 | 1st 05/20/2018 to 09/08/2021 | Fall 2019 | H1R22 |
| | | Spring 2021 | H1R23 |
| | 2nd 09/09/2021 to 09/08/2024 | Fall 2022 | H1R24 |
| | | Spring 2024 | H1R25 |
| | 3rd 09/09/2024 to 09/08/2027 | Fall 2025 | H1R26 |
| | | Spring 2027 | H1R27 |

| **Table 3.4.2-2, FOURTH CISI INTERVAL/PERIOD/OUTAGE MATRIX [1] (FOR CISI CLASS MC COMPONENT EXAMINATIONS – IWE Only)** | | | |
|---|---|---|---|
| **Interval** | **Period** | **Outages** | |
| **Start Date to End Date** | **Start Date to End Date** | **Outage Dates During Inspection Period** | **Outage Number** |
| 4th 09/09/2027 to 09/08/2037 | 1st 09/09/2027 to 09/08/2031 | Fall 2028 | H1R28 |
| | | Spring 2030 | H1R29 |
| | 2nd 09/09/2031 to 09/08/2034 | Fall 2031 | H1R30 |
| | | Spring 2033 | H1R31 |
| | 3rd 09/09/2034 to 09/08/2037 | Fall 2034 | H1R32 |
| | | Spring 2036 | H1R33 |

Note 1: The dates and outages for the fourth CISI interval are projected as the plan has not yet been developed.

| **Table 3.4.2-3, THIRD CISI INTERVAL/PERIOD/OUTAGE MATRIX (FOR CISI CLASS CC COMPONENT EXAMINATIONS – IWL Only)** | | | |
|---|---|---|---|
| **Start Date to End Date** | **Start Date to End Date (2 year window)[2]** | **Outage Dates During Examination Window** | **Outage Number** |
| 3rd<br>05/20/2018 to 09/08/2027 | 05/20/2018 to 09/07/2020 (IWL Exams are not Permitted During this Time) | Fall 2019 | H1R22 |
| | Period 1 – 09/08/2021 (+/- 12 Months) (09/08/2020 to 09/07/2022) [1] | Spring 2021 | H1R23 |
| | 09/08/2022 to 09/07/2025 (IWL Exams are not Permitted During this Time) | Fall 2022 | H1R24 |
| | | Spring 2024 | H1R25 |
| | Period 2 – 09/08/2026 (+/- 12 Months) (09/08/2025 to 09/07/2027) [1] | Fall 2025 | H1R26 |
| | | Spring 2027 | H1R27 |

Note 1: The CISI Interval for Class CC components is the same as the CISI Interval for Class MC components. The actual inspection schedule for Class CC components is based on a rolling 5-year frequency (+/- 1 year) from the date of completion of the original examinations (09/07/2001) performed during the initial September 9, 1996 – September 8, 2001, rulemaking implementation period. The rolling 5-year inspection schedule for CC is in accordance with the ISI schedule specified in IWL-2400 as modified by the initial regulatory rulemaking.

Note 2: 10 CFR 50.55a(g)(6)(ii)(B)(2), which no longer exists in the regulation, allowed licensees to modify the examination schedule for CC examinations based on a 5-year interval from the date on which completion of the initial concrete examinations were completed. The schedule for successive examinations was established based on the initial examinations having been completed on September 7, 2001. The 2nd rolling exam window was 9/7/2006 (+/- 12 months), 3rd window was 9/7/2011 (+/- 12 months), 4th window was 9/7/2016 (+/- 12 months).

<table>
<tr><th colspan="4">Table 3.4.2-4, FOURTH CISI INTERVAL/PERIOD/OUTAGE MATRIX[1]<br>(FOR CISI CLASS CC COMPONENT EXAMINATIONS – IWL Only)</th></tr>
<tr><th>Start Date to End Date</th><th>Start Date to End Date</th><th>Outage Dates During Examination Window</th><th>Outage Number</th></tr>
<tr><td rowspan="6">4th<br>09/09/2027 to 09/08/2037</td><td>05/20/2028 to 09/07/2030<br>(IWL Exams are not Permitted During this Time)</td><td>Fall 2028</td><td>H1R28</td></tr>
<tr><td>Period 1 – 09/08/2031<br>(+/- 12 Months)<br>(09/08/2020 to 09/07/2022) [1]</td><td>Spring 2030</td><td>H1R29</td></tr>
<tr><td rowspan="2">09/08/2032 to 09/07/2035<br>(IWL Exams are not Permitted During this Time)</td><td>Fall 2031</td><td>H1R30</td></tr>
<tr><td>Spring 2033</td><td>H1R31</td></tr>
<tr><td rowspan="2">Period 2 – 09/08/2036<br>(+/- 12 Months)<br>(09/08/2035 to 09/07/2037) [1]</td><td>Fall 2034</td><td>H1R32</td></tr>
<tr><td>Spring 2036</td><td>H1R33</td></tr>
</table>

Note 1: The dates and outages for the fourth CISI interval are projected as the plan has not yet been developed.

**Applicable Editions and Addenda to ASME Section XI**

In accordance with the requirements of 10 CFR 50.55a(g)(4)(ii) (79 FR 73462, December 11, 2014), the CISI of HNP shall be performed in accordance with Section XI, subject to conditions as follows:

10 CFR 50.55a Conditions

The following mandatory and optional Code of Federal Regulations Conditions are included in 10 CFR 50.55a (82 FR 32934, July 18, 2017). These conditions were reviewed for inclusion in the ISI Plan and include only those 10 CFR 50.55a conditions applicable to the 2007 Edition through the 2008 Addenda of Section XI. HNP shall implement these requirements for the fourth interval as follows:

- 10 CFR 50.55a(b)(2)(vi) Section XI condition: Effective edition and addenda of Subsection IWE and Subsection IWL. Licensees that implemented the expedited examination of containment, in accordance with Subsection IWE and Subsection IWL, during the period from September 9, 1996, to September 9, 2001, may use either the 1992 Edition with the 1992 Addenda or the 1995 Edition with the 1996 Addenda of Subsection IWE and Subsection IWL, as conditioned by the requirements in paragraphs (b)(2)(viii) and (ix) of this section, when implementing the initial 120-month inspection interval for the containment inservice inspection requirements of this section. Successive 120-month interval updates must be implemented in accordance with paragraph (g)(4)(ii) of this section.

HNP shall schedule successive 120-month interval updates for Class MC and CC components in accordance with §50.55a(g)(4)(ii).

- 10 CFR 50.55a(b)(2)(viii) Section XI condition: Concrete Containment examinations. Applicants or licensees applying Subsection IWL, 2007 Edition up to and including the 2008 Addenda must apply paragraph (b)(2)(viii)(E) of this section.

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

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

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

  (3) A description of necessary corrective actions.

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

  10 CFR 50.55a(b)(2)(ix)(A) – Metal Containment examinations: First provision. For Class MC applications, the following apply to inaccessible areas:

  (1) The applicant or licensee must evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of or could result in degradation to such inaccessible areas.

  (2) For each inaccessible area identified for evaluation, the applicant or licensee must provide the following in the ISI Summary Report as required by IWA-6000:

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

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

  (iii) A description of necessary corrective actions.

**ASME Code Cases**

All ASME Code Cases listed in Table 1 and Table 2 of NRC RG 1.147, Revision 17 (Reference 33) are approved for use during the HNP fourth ISI and third CISI intervals and may be used, even if they are not listed in the program plan, provided the Code Case revision is applicable to the 2007 Edition through the 2008 Addenda.

**Subsection IWE for Class MC and Metallic Liners of Class CC**

The IWE examinations are based upon the requirements of ASME Section XI. Specific examinations are based on the requirements of the ASME B&PV Code, Section XI, Table IWE-2500-1.

**Table 3.4.2-5, IWE-2500-1, Examination Category E-A, Containment Surfaces**

| Item Numbers | Parts Examined | Number of Items | Number of Examinations Scheduled by Period | | |
|---|---|---|---|---|---|
| | | | 1 | 2 | 3 |
| E1.11 | Accessible Surface Areas[1] | 178 | 178 | 178 | 178 |
| E1.12 | Wetted Surfaces of Submerged Areas | N/A | N/A | N/A | N/A |
| E1.20 | BWR Vent System Accessible Surface Areas | N/A | N/A | N/A | N/A |
| E1.30 | Moisture Barrier[3] | 5[2] | 5 | 5 | 5 |

Notes:

1. Portions of the surfaces (including bolted connections) of electrical penetrations are considered inaccessible for general visual examination in accordance with Category E-A, E1.11 because welded electrical junction boxes are attached just off of the containment wall, not allowing sufficient space to perform this visual examination. Containment bolted connections shall be scheduled for examination in accordance with Category E-G.

2. At the start of the third containment ISI interval there is an additional task due to NRC Regulatory Issue Summary (RIS) 2016-07, "Containment Shell or Liner Moisture Barrier Inspection." There is one summary number that represents the E1.30 for contingency findings but it is only scheduled for RFO23 in the third interval.

3. HNP performed an evaluation and found no items that had to be addressed as a result of NRC Information Notice (IN) 2014-17, “Degradation of Leak-Chase Channel Systems for Floor Welds of Metal Containment Shell and Concrete Containment Metallic Liner."

| Table 3.4.2-6, IWE-2500-1, Examination Category E-C[1], Containment Surfaces Requiring Augmented Examination | | | | | |
|---|---|---|---|---|---|
| Item Numbers | Parts Examined | Number of Items | Number of Examinations Scheduled by Period | | |
| | | | 1 | 2 | 3 |
| E4.10<br>E4.11 | Containment Surface Areas<br>Visible Surfaces | None[2] | 1[3] | 0 | 0 |
| E4.12 | Surface Area Grid – Minimum Wall Thickness Location | None[2] | 0 | 0 | 0 |

Notes:

1. In accordance with the third Ten-Year Interval Containment Inservice Inspection Plan and Schedule, if areas are identified requiring augmented examinations (E-C) during the interval, then they will be listed in the "E-C AUGMENT" section of the third Ten-Year Interval Containment Inservice Inspection Schedule.

2. At the start of the third Containment ISI Interval, there were no items identified requiring examination in accordance with Category E-C, E4.12. There is one summary number that represents the E4.11 for contingency use but no scheduling exists as of the start of the third interval.

3. One augmented exam has been added to Category E-C, Item E4.11 for the third Containment ISI Interval. This area is normally considered inaccessible for examination in accordance with Item E1.11 because of extensive lead shielding that would have to be removed on the exterior side of the containment in the vicinity of the fuel transfer tube Penetration S-65. Examination may be discontinued after the first examination of this area if there are no conditions observed during the examination that warrant continued examination in accordance with IWE-2420(b).

| Table 3.4.2-7, IWE-2500-1, Examination Category E-G[1], Pressure Retaining Bolting | | | | | |
|---|---|---|---|---|---|
| Item Numbers | Parts Examined | Number of Items | Number of Examinations Scheduled by Period | | |
| | | | 1 | 2 | 3 |
| E8.10 | Bolted Connections | 90 | 54 | 36 | 0 |

Notes:

1. 100% of exams are required to be performed by the end of Interval. Deferral to the end of the interval is permissible.

**Subsection IWL for Class CC**

The IWL examinations are based upon the requirements of ASME Section XI. Specific examinations are based on the requirements of the ASME B&PV Code, Section XI, Table IWL-2500-1 and the Third Ten-Year IWE/IWL Schedule.

Examination frequency shall be every 5 years, based on the initial inspection date of September 7, 2001 and every 5 years thereafter. The examinations shall commence no more than 12 months prior to the specified dates and shall be completed no more than 12 months after the specified dates.

| Table 3.4.2-7, IWL-2500-1, Examination Category L-A, Concrete | | |
|---|---|---|
| **Item Numbers** | **Parts Examined** | **Areas Required to be Examined During Each Period [1]** |
| L1.10<br>L1.11 | Concrete Surface<br>All accessible surface areas | 100% (22 of 22 areas) |
| L1.12 | Suspect Areas | 100% (If any) [2] |

Notes:

1. The IWL examination periods do not align with those for Class 1, 2, 3, and MC components.

2. At the start of the third Containment ISI Interval, there were no items identified requiring examination in accordance with Category L-A, Item L1.12. There is one summary number that represents the L1.12 for contingency use but it has no scheduling assigned at start of third interval.

**Responsible Engineer**

Per IWL-2330, the Responsible Engineer shall be a Registered Professional Engineer experienced in evaluating the condition of structural concrete. The Responsible Engineer shall have knowledge of the design and Construction Codes and other criteria used in design and construction of concrete containments in nuclear power plants.

**Relief Requests**

Each request for relief from a requirement of the ASME Section XI Code specified in the plan shall be submitted to the NRC for review and approval. Refer to Section 3.1.3 of this submittal for a description of RR I3R-18 (Reference 16), which affects HNP during the third CISI interval.

### 3.4.3 Supplemental Inspection Requirements

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

> Subsections IWE and IWL of the ASME Code, Section XI, as incorporated by reference in 10 CFR 50.55a, require general visual examinations two times within a 10-year interval for concrete components (Subsection IWL), and three times within a 10-year interval for steel components (Subsection IWE). To avoid duplication or deletion of examinations, licensees using NEI TR 94-01, Revision 2, have to develop a schedule for containment inspections that satisfy the provisions of Section 9.2.3.2 of this TR and ASME Code, Section XI, Subsection IWE and IWL requirements.

The performance of inspections in accordance with the requirements of HNP TS SR 4.6.1.6.1 shall be performed as described below (based on the proposed changes of this LAR) to ensure compliance with the visual inspection requirements of NEI 94-01, Revision 3-A:

> 4.6.1.6.1 <u>Containment Vessel Surfaces.</u> The structural integrity of the exposed accessible interior and exterior surfaces of the containment vessel, including the liner plate, shall be determined, during the shutdown for each Type A containment leakage rate test (reference Specification 4.6.1.1.c), by a visual inspection of these surfaces. This inspection shall be performed prior to the Type A containment leakage rate test to verify no apparent changes in appearance or other abnormal degradation. Additional inspections shall be conducted in accordance with Subsections IWE and IWL of the ASME Boiler and Pressure Vessel Code, Section XI.

### 3.4.4 Results of Recent Containment Examinations

The results of recent visual examinations of IWE surfaces are detailed in Tables 3.4.4-1 and 3.4.4-3 below. Note that the contents of Tables 3.4.4-1 and 3.4.4-3 do not include the results of inspections where there were No Reportable Indications and the inspection results were evaluated and found acceptable.

The results of recent visual examinations of IWL surfaces are detailed in Table 3.4.4-2 below. Note that the contents of Table 3.4.4-2 do not include the results of inspections where there were No Reportable Indications and the inspection results were evaluated and found acceptable.

| Table 3.4.4-1, H1R19 Visual Examination of IWE Surfaces (VT-3) | | | | | |
|---|---|---|---|---|---|
| **Component ID** | **Location** | **Description** | **Exam Type** | **Direct/ Remote** | **Comments** |
| LC-0/90 | All elevations | Containment Liner Quadrant 0° - 90° | E-A/E1.11 | Direct/Remote | No additional bulging of liner that was recorded on previous report. Light rust at approximately 80°AZ [azimuth] 15" long by 1" wide, just above moisture barrier seal. Results SAT. |
| LC-90/180 | All elevations | Containment Liner Quadrant 90° - 180° | E-A/E1.11 | Direct/Remote | Minor chips in various areas. No additional bulging of liner that was recorded on previous report. Results SAT. |
| LC-180/270 | All elevations | Containment Liner Quadrant 180° - 270° | E-A/E1.11 | Direct/Remote | Minor chips in various areas. Results SAT. |
| LC-270/360 | All elevations | Containment Liner Quadrant 270° - 360° | E-A/E1.11 | Direct/Remote | AZ 270°-285° Discoloration. Minor chips in various areas. Light rust, no material loss. No additional bulging of liner that was on previous report. Results SAT. |
| M-90/180 | 221' | Moisture Barrier Quadrant 90° to 180° | E-A/E1.30 | Direct | 1/2" plastic tube in moisture barrier at approximately 120°. Results SAT. |
| M-180/270 | 221' | Moisture Barrier Quadrant 180° to 270° | E-A/E1.30 | Direct | 1/2" plastic tube in moisture barrier at approximately 190°. Area of concern at barrier inspected. Area of concern at |

| Table 3.4.4-1, H1R19 Visual Examination of IWE Surfaces (VT-3) | | | | | |
|---|---|---|---|---|---|
| **Component ID** | **Location** | **Description** | **Exam Type** | **Direct/ Remote** | **Comments** |
| | | | | | AZ. 165° behind vent duct was inspected and accepted. |
| M-270/360 | 221' | Moisture Barrier Quadrant 270° to 360° | E-A/E1.30 | Direct | 1/2" plastic tube in moisture barrier at approximately 280°. Results SAT. |
| S-1 | 280°/218' | Sleeve (56") S-1 - Mech. Pen. M-1 | E-A/E1.11 | Direct | Heavy flaking in coating. Results SAT. |
| S-4 | 280°/271' | Sleeve (30") S-4 - Mech. Pen. M-4 | E-A/E1.11 | Direct | Coatings flaking near cooling fans. Light surface rust. Results SAT. |
| S-9 | 342°/255' | Sleeve (10") S-9 - Mech. Pen. M-9 | E-A/E1.11 | Direct | Light discoloration. Results SAT. |
| S-13 | 260°/251' | Sleeve (18") S-13 - Mech. Pen. M-13 | E-A/E1.11 | Direct | Light rust with no material loss noted. Results SAT. |
| S-47 | 315°/216' | Sleeve (30") S-47 - Mech. Pen. M-47 | E-A/E1.11 | Direct | Inspected from inside Containment Spray Valve Chamber, Light rust found with no material loss. Results SAT. |
| S-VC1 | 315°/190' | Valve Chamber 1A-SA Elect. Pen. | E-A/E1.11 | Direct | Coating is chipping, blistering, and flaking on O.D. at approximately 4 to 6 o'clock. Light rust with no metal loss noted. Calcium deposits also noted. Results SAT. |

| Table 3.4.4-1, H1R19 Visual Examination of IWE Surfaces (VT-3) | | | | | |
|---|---|---|---|---|---|
| **Component ID** | **Location** | **Description** | **Exam Type** | **Direct/ Remote** | **Comments** |
| S-48 | 225°/216' | Sleeve (30") S-48 - Mech. Pen. M-48 | E-A/E1.11 | Direct | Inspected from inside of Containment Spray Valve Chamber, Light rust with no material loss |
| S-49 | 315°/216' | Sleeve (30") S-49 - Mech. Pen. M-49 | E-A/E1.11 | Direct | Inspected from inside of RHR Valve Chamber, Light rust found with no material loss. Results SAT. |
| S-VC3 | 315°/190' | Valve Chamber 1A-SA Elect. Pen. | E-A/E1.11 | Direct | Coatings are flaking, blistering, and chipping on O.D. at approximately 2 to 10 o'clock, Light rust with no material loss. Results SAT. |
| S-50 | 225°/216' | Sleeve (30") S-50 - Mech. Pen. M-50 | E-A/E1.11 | Direct | Inspected from inside of RHR Valve Chamber, Light rust found with no material loss. Results SAT. |
| S-52 | 272°/255' | Sleeve (10") S-52 - Mech. Pen. M-52 | E-A/E1.11 | Direct | Light rust on sleeve to pipe weld. Results SAT. |
| S-53 | 186°/255' | Sleeve (10") S-53 ·Mech. Pen. M-53 | E-A/E1.11 | Direct | Light rust on sleeve weld. Results SAT. |
| S-54 | 352°/2551 | Sleeve (10") S-54 ·Mech. Pen. M-54 | E-A/E1.11 | Direct | Coatings missing on sleeve end plate, no rust noted. Results SAT. |
| S-55 | 276°/255' | Sleeve (10") S-55 - Mech. Pen. M-55 | E-A/E1.11 | Direct | Paint flaking with light, rust on sleeve and plate. Results SAT. |

| Table 3.4.4-1, H1R19 Visual Examination of IWE Surfaces (VT-3) | | | | | |
|---|---|---|---|---|---|
| **Component ID** | **Location** | **Description** | **Exam Type** | **Direct/ Remote** | **Comments** |
| S-56 | 190°/255' | Sleeve (10") S-56 - Mech. Pen. M-56 | E-A/E1.11 | Direct | Light rust on end plate. Results SAT. |
| S-64 | 170°/251' | Sleeve (18") S-64- Spare | E-A/E1.11 | Direct | Chip in coating. Results SAT. |
| S-74 | 215°/230' | Sleeve (10") S-74 - Mech. Pen. M-74 | E-A/E1.11 | Direct | Light rust on sleeve and plate. Results SAT. |
| S-150 | 346°/298' | Sleeve (24') S-150- Mech. Pen. M-150 | E-A/E1.11 | Direct | Flaking, blistering and peeling coatings on outside surfaces with rust. No material loss noted. Results SAT. |
| BV-M150 | 346°/298' | Equipment Hatch Bolted Connection | E-A/E1.11 | Direct | Minor flat areas on threads outside of nut engagement area. Inspected 36 bolts, nuts, and washers. Results SAT. |
| S-152 | 170°/261' | Sleeve (5') S-152 - Mech. Pen. M-152 | E-A/E1.11 | Direct | Chipping of coatings on outside surfaces. No rust noted. Results SAT. |

| Table 3.4.4-2, H1R20 Visual Examination of IWL (VT-3C) | | | | | |
|---|---|---|---|---|---|
| **Component ID** | **Location** | **Description** | **Exam Type** | **Direct/ Remote** | **Comments** |
| CC-180/270 | All Elevations - Except Dome | Concrete Surface | L-A/L1.11 | Direct/Remote | 1. Reactor Auxiliary Building (RAB) EL 190', ED Transfer Pump Room there are cracks approximately 0.020" in width with active leaching.<br>Evaluation:<br>This is a pre-existing condition previously identified during the 2006 IWL Inspection. Observed area of leaching is located on RAB EL. 190' on the east side of the containment exterior.<br><br>The leaching occurs at a construction joint located at EL 204'. The leaching is located in a locked high radiation area. Part of the leaching can be observed from outside the locked high radiation area, but the remainder of the leaching can only be observed by entering the locked high radiation area. All of the leaching is white calcium silicate with no evidence of rust staining or rebar degradation. The condition is acceptable as-is. |
| | | | | | 2.RAB EL 216' Penetration 100, leakage on concrete around penetration with rust stains on wall.<br>Evaluation:<br>This containment penetration 100 is located on the exterior wall of Containment Building near 37 line and I line at approximate EL 230'. The penetration is a spare and is blanked off. There is evidence that some seepage has occurred in the past due to faint rust stains on the painted surface below and the unpainted concrete is darkened. The wall is currently dry. There is no path for groundwater to exit at this point. It is likely that rainwater or condensation has dripped down the seismic gap in this area. The exposed metal on the penetration is not corroded. This condition is judged not adverse to the structural |

| Table 3.4.4-2, H1R20 Visual Examination of IWL (VT-3C) | | | | | |
|---|---|---|---|---|---|
| **Component ID** | **Location** | **Description** | **Exam Type** | **Direct/ Remote** | **Comments** |
| | | | | | integrity of the containment exterior wall and is acceptable as-is. |
| | | | | | 3.RAB EL 286' at azimuth 255° there are three drill holes 3/4" in diameter. The top two are three inches deep, and the bottom is six inches deep.<br>Evaluation:<br>These holes are located in the exterior wall of Containment Building. There is no evidence of rebar degradation or damage as there is no rust staining evident. These drilled holes are structurally acceptable to be left as-is; however, a Work Request (WR) was created to cosmetically repair/fill these drilled holes using non-shrink grout (dry pack) or epoxy grout. |
| CC-270/360 | All Elevations - Except Dome | Concrete Surface | L-A/L 1.11 | Direct/Remote | 1.RAB EL 190' Concrete cut out at RHR Valve Chamber exposed two pieces of rebar. The coating is flaking off with light rust.<br>Evaluation:<br>This is a pre-existing condition originally identified during the 2001 IWL Inspection. This location is actually EL 190' North at the Containment Spray (CS) valve chamber. The concrete cut-out, which exposed the rebar is shown on drawings. The observed size of the concrete cut-out is consistent with the information provided on these drawings. The coatings on the exposed rebar are flaking off with light rust; however, the rebar itself is in very good condition. The condition is acceptable as-is based on the information provided in the design drawings. |
| | | | | | 2.RAB EL 190' at approximately azimuth 10° there appears to be two pieces of coated metal protruding from the wall. |

| Table 3.4.4-2, H1R20 Visual Examination of IWL (VT-3C) | | | | | |
|---|---|---|---|---|---|
| **Component ID** | **Location** | **Description** | **Exam Type** | **Direct/ Remote** | **Comments** |
| | | | | | Evaluation:<br>These are threaded form tie bolts used to attach the wooden forms for concrete placements. After the concrete was placed and the wooden forms removed, these tie bolts remained exposed. Most tie bolts were broken off below the concrete surface and the hole cosmetically patched with dry pack grout; however, these two were not. These bolts are located in a protected interior area and there is no mechanism for corrosion. These tie bolts are acceptable to be left as-is. |
| | | | | | 3.RAB EL 216' azimuth 350° appears to be oil/grease leaking.<br>Evaluation:<br>The oil/grease is on the surface of a coated area and did not originate from the concrete under the coating. It appears to have been mechanically placed on the surface. The condition is acceptable as-is. |
| CD-0/180 | Concrete Cont. Dome above 376' El. | Concrete Dome Surface | L-A/L1.11 | Direct/Remote | 1. The construction joint seal at elevation 386' between grout and concrete is separating from the grout and is cracking.<br>Evaluation:<br>The elastomeric seal (appears to be Hornflex or equal) has been exposed to years of weather and UV. The seal does not perform any safety related or structural function - It is there to prevent water from ponding and causing freeze-thaw damage to the concrete. The inspection photos showed the concrete is spalling in this area. Lack of maintenance on the seal will result in slow degradation of surrounding grout and concrete. WR was created to repair/replace the seal. |
| | | | | | 2. Several areas of exposed welded wire fabric material found in addition to the areas around the dome ladder noted on previous report. |

| Table 3.4.4-2, H1R20 Visual Examination of IWL (VT-3C) | | | | | |
|---|---|---|---|---|---|
| **Component ID** | **Location** | **Description** | **Exam Type** | **Direct/ Remote** | **Comments** |
| | | | | | Evaluation:<br>Concrete details for the dome are shown on drawings. Expanded wire mesh was used as the exterior form and was left in place after the dome concrete placements. While the concrete was still green, a minimum 3/8" thick layer of stiff grout was troweled over to completely cover the expanded wire mesh. This grout was considered cosmetic and was a purely aesthetic application intended to prevent unsightly concrete staining due to rusting of unprotected expanded wire mesh. The inspection photos show that the 3/8" grout cover has spalled in places and left the expanded wire mesh exposed. The missing grout does not affect the structural integrity of the reinforced concrete dome. A 2-3/4" clear concrete cover is maintained over the rebar without the cosmetic grout. This condition is acceptable as-is. |
| CD-180/360 | Concrete Cont. Dome above 376' El. | Concrete Dome Surface | L-A/L1.11 | Direct/Remote | 1.The construction joint seal at elevation 386' between grout and concrete is separating from the grout and Is cracking.<br>Evaluation:<br>The elastomeric seal (appears to be Hornflex or equal) has been exposed to years of weather and UV. The seal does not perform any safety related or structural function - it is there to prevent water from ponding and causing freeze-thaw damage to the concrete. The inspection photos showed the concrete is spalling in this area. Lack of maintenance on the seal will result in slow degradation of surrounding grout and concrete. WR was created to repair/replace the seal. |
| | | | | | 2. Several areas of exposed welded wire fabric material found in addition to the areas around the dome ladder noted on previous report. |

| Table 3.4.4-2, H1R20 Visual Examination of IWL (VT-3C) | | | | | |
|---|---|---|---|---|---|
| **Component ID** | **Location** | **Description** | **Exam Type** | **Direct/ Remote** | **Comments** |
| | | | | | Evaluation:<br>Concrete details for the dome are shown on drawings. In addition, expanded wire mesh was used as the exterior form and was left in place after the dome concrete placements. While the concrete was still green, a minimum 3/8" thick layer of stiff grout was troweled over to completely cover the expanded wire mesh. This grout was considered cosmetic and was a purely aesthetic application intended to prevent unsightly concrete staining due to rusting of unprotected expanded wire mesh.<br>The inspection photos show that the 3/8" grout cover has spelled in places and left the expanded wire mesh exposed. The missing grout does not affect the structural integrity of the reinforced concrete dome. A 2-3/4" clear concrete cover is maintained over the rebar without the cosmetic grout. This condition is acceptable as-is. |
| CD-180/360 | Concrete Cont. Dome above 376' El. | Concrete Dome Surface | L-A/L1.11 | Direct/Remote | 1. The construction joint seal at elevation 386' between grout and concrete is separating from the grout and Is cracking.<br>Evaluation:<br>The elastomeric seal (appears to be Hornflex or equal) has been exposed to years of weather and UV. The seal does not perform any safety related or structural function - it is there to prevent water from ponding and causing freeze-thaw damage to the concrete. The inspection photos showed the concrete is spalling in this area. Lack of maintenance on the seal will result in slow degradation of surrounding grout and concrete. WR was created to repair/replace the seal. |

| Table 3.4.4-2, H1R20 Visual Examination of IWL (VT-3C) | | | | | |
|---|---|---|---|---|---|
| **Component ID** | **Location** | **Description** | **Exam Type** | **Direct/ Remote** | **Comments** |
| | | | | | 2. Several areas of exposed welded wire fabric material found in addition to the areas around the dome ladder noted on previous report.<br>Evaluation:<br>Concrete details for the dome are shown on drawings. Expanded wire mesh was used as the exterior form and was left in place after the dome concrete placements. While the concrete was still green, a minimum 3/8" thick layer of stiff grout was troweled over to completely cover the expanded wire mesh. This grout was considered cosmetic and was a purely aesthetic application intended to prevent unsightly concrete staining due to rusting of unprotected expanded wire mesh. The inspection photos show that the 3/8" grout cover has spalled in places and left the expanded wire mesh exposed. The missing grout does not affect the structural integrity of the reinforced concrete dome. A 2-3/4" clear concrete cover is maintained over the rebar without the cosmetic grout. This condition is acceptable as-is. |
| CD-0/180 | Concrete Cont. Dome above 376' El. | Concrete Dome Surface | L-A/L1.11 | Direct | Surface cracking was identified in various locations on top of the dome. The cracking appears to be greater than 0.040" in width. Cracking greater than 0.040" is unacceptable and requires engineering evaluation. A follow up VT-1 could not be performed due to access limitations and safety concerns. Pictures were taken and given to the IWL RE for evaluation. The surface cracking is in the non-structural grout cover of the dome. No leaching was identified coming from cracks. The cracks were seen in previous history pictures but have not been identified as evaluated in previous history reports.<br>Evaluation: |

| Table 3.4.4-2, H1R20 Visual Examination of IWL (VT-3C) | | | | | |
|---|---|---|---|---|---|
| **Component ID** | **Location** | **Description** | **Exam Type** | **Direct/ Remote** | **Comments** |
| | | | | | This is a pre-existing condition that has been seen in previous history reports but was not reported as a defect. The outside dome reinforcement has a 4 1/2" (min.) tall rebar chair attached with expanded wire mesh attached to the chair to make a form for placement of the dome concrete. After the dome concrete placement, a 3/8" (min.) skim coat of grout is placed on the wire mesh to protect it from corrosion. Any cracking in the skim coat is considered cosmetic and will have no impact on the structural reinforcement, which has a minimum of 4" cover. This condition is judged not adverse to the structural integrity of the containment dome and is acceptable as-is. |
| CD-180/360 | Concrete Cont. Dome above 376' El. | Concrete Dome Surface | L-A/L1.11 | Direct | Surface cracking was identified in various locations on top of the dome. The cracking appears to be greater than 0.040" in width. Cracking greater than 0.040" is unacceptable and requires engineering evaluation. A follow up VT-1 could not be performed due to access limitations and safety concerns. Pictures were taken and given to the IWL RE for evaluation. The surface cracking is in the non-structural grout cover of the dome. No leaching was identified coming from cracks. The cracks were seen in previous history pictures but have not been identified as evaluated in previous history reports.<br>Evaluation:<br>This is a pre-existing condition that has been seen in previous history but was never reported as a defect. The outside dome reinforcement has a 4 1/2" (min.) tall rebar chair attached with expanded wire mesh attached to the chair to make a form for placement of the dome concrete. After the dome concrete placement, a 3/8" (min.) skim coat of grout is placed on the wire mesh to protect it from corrosion. Any cracking in the skim |

| Table 3.4.4-2, H1R20 Visual Examination of IWL (VT-3C) | | | | | |
|---|---|---|---|---|---|
| **Component ID** | **Location** | **Description** | **Exam Type** | **Direct/ Remote** | **Comments** |
| | | | | | coat is considered cosmetic and will have no impact on the structural reinforcement, which has a minimum of 4 1/2" cover. This condition is judged not adverse to the structural integrity of the containment dome and is acceptable as-is. |

| Table 3.4.4-3, H1R21 Visual Examination of IWE Surfaces (VT-3) | | | | | |
|---|---|---|---|---|---|
| **Component ID** | **Location** | **Description** | **Exam Type** | **Direct/ Remote** | **Comments** |
| S-46 | 174°/230' | Sleeve (10") S-46 - Spare | E-A/E1.11 | Direct | Paint missing in areas with a primer coat visible. No rusting or material loss noted. No changes from previous reports. No evaluation is required. |
| S-2 | 270°/278' | Sleeve (56") S-2 - Mech. Pen. M-2 | E-A/E1.11 | Direct | The Coatings Program Manager and Paint Shop Supervisor have evaluated the degraded coatings conditions. These areas will be incorporated into the inspection results from Inspection of SL1 coatings inside RCB and repaired via WO. These types of coatings issues are not uncommon and can be expected each outage. The paint shop has a periodic maintenance (PM) to perform routine touchups such as these in RCB. No additional evaluation is required. |
| M-0/90 | 221' | Moisture Barrier Quadrant 0° to 90° Liner Shell at Embedment Z | E-A/E1.30 | Direct | RIS Item Description: 0°-360° Electrical conduit attached to containment liner by way of octagonal metal plates welded to the liner. These supports do not have welds on the horizontal or vertical plate to liner interface. Supports are located from 0° AZ to 360° AZ at all elevations.<br>Resolution:<br>The inaccessible surfaces behind the octagonal metal plates need not be subject to the Augmented Examinations in accordance with IWE-1241. The items are coated. The vertical and horizontal sides of the plate are caulked. Available pictures |

| Table 3.4.4-3, H1R21 Visual Examination of IWE Surfaces (VT-3) | | | | | |
|---|---|---|---|---|---|
| Component ID | Location | Description | Exam Type | Direct/ Remote | Comments |
| | | | | | of these components do not indicate any evidence of degradation of the octagonal plates, weld, or the liner, in the form of rusting, coating or caulking failure or staining. No coating, weld, liner, or octagonal metal plate degradation is identified in the inspection report. The surface areas are not subject to experiencing accelerated corrosion, degradation, or aging of the liner or coatings. The locations are not exposed to standing water, repeated wetting and drying, persistent leakage, water accumulation, condensation, or microbiological attack. These areas are not subject to excessive wear from abrasion or erosion, which would cause a loss of protective coatings, deformation or material loss. |
| | | | | | RIS Item Description: Elev. 286' - 0°-360° Vent Ductwork supports welded to containment liner. These supports have 1" of gap in weld in the center of the lower horizontal weld.<br>Resolution:<br>The items described are square plates welded to the liner with no components attached to the plates. Per the typical pad to shell weld detail provided, the weld is continuous around the plate, except for the gap in the lower horizontal weld. The inaccessible surfaces behind the square metal plates need not be subject to the Augmented Examinations in accordance with IWE-1241. The items are coated. Available pictures of these components do not indicate any evidence of degradation of the square plates, weld, or the liner in the form of rusting, coating failure, or staining. No coating, weld, liner, or square metal plate degradation is identified in the inspection report. The surface areas are not subject to experiencing accelerated corrosion, degradation, or aging of the liner or coatings. The locations are |

| Table 3.4.4-3, H1R21 Visual Examination of IWE Surfaces (VT-3) | | | | | |
|---|---|---|---|---|---|
| **Component ID** | **Location** | **Description** | **Exam Type** | **Direct/ Remote** | **Comments** |
| | | | | | not exposed to standing water, repeated wetting and drying, persistent leakage, water accumulation, condensation, or microbiological attack. These areas are not subject to excessive wear from abrasion or erosion, which would cause a loss of protective coatings, deformation or material loss. |
| M-90/180 | 221' | Moisture Barrier Quadrant 90° to 180° Liner Shell at Embedment | E-A/E1.30 | Direct | RIS Item: 0°-360° Electrical conduit attached to containment liner by way of octagonal metal plates welded to the liner. Supports do not have welds on horizontal or vertical plate to liner interface. Located from AZ 0° to 360° at all elevations.<br>Resolution:<br>The inaccessible surfaces behind the octagonal metal plates need not be subject to the Augmented Examinations in accordance with IWE-1241. The items are coated. The vertical and horizontal sides of the plate are caulked. Available pictures of these components do not indicate any evidence of degradation of the octagonal plates, weld, or the liner, in the form of rusting, coating or caulking failure, or staining. No coating, weld, liner, or octagonal metal plate degradation is identified in the inspection report. The surface areas are not subject to experiencing accelerated corrosion, degradation, or aging of the liner or coatings. The locations are not exposed to standing water, repeated wetting and drying, persistent leakage, water accumulation, condensation, or microbiological attack. These areas are not subject to excessive wear from abrasion or erosion, which would cause a loss of protective coatings, deformation or material loss. |
| | | | | | RIS Item: Elev. 286' - 0°-360° Vent Ductwork supports welded to containment liner. These supports have 1" of gap in weld in the center of the lower horizontal weld. Resolution: |

| Table 3.4.4-3, H1R21 Visual Examination of IWE Surfaces (VT-3) | | | | | |
|---|---|---|---|---|---|
| **Component ID** | **Location** | **Description** | **Exam Type** | **Direct/ Remote** | **Comments** |
| | | | | | The items described are square plates welded to the liner with no components attached to the plates. Per the typical pad to shell weld detail, the weld is continuous around the plate, except for the gap in the lower horizontal weld. The inaccessible surfaces behind the square metal plates need not be subject to the Augmented Examinations in accordance with IWE-1241. The items are coated. Available pictures of these components do not indicate any evidence of degradation of the square plates, weld or the liner in the form of rusting, coating failure or staining. No coating, weld, liner, or square metal plate degradation is identified in the inspection report. The surface areas are not subject to experiencing accelerated corrosion, degradation, or aging of the liner or coatings. The locations are not exposed to standing water, repeated wetting and drying, persistent leakage, water accumulation, condensation, or microbiological attack. These areas are not subject to excessive wear from abrasion or erosion, which would cause a loss of protective coatings, deformation or material loss. |
| | | | | | RIS Item: Elev. 261' - 140°-160° Twelve rectangular plates welded to containment liner in four vertical rows of three. These supports have 1" of gap in weld in the center of the lower horizontal weld.<br>Resolution:<br>From conversation with the summary report Level III reviewer, the items described are square plates welded to the liner with no components attached to the plates. Per the typical pad to shell weld detail, the weld is continuous around the plate, except for the gap in the lower horizontal weld. The inaccessible surfaces behind the square metal plates need not be subject to the |

| Table 3.4.4-3, H1R21 Visual Examination of IWE Surfaces (VT-3) | | | | | |
|---|---|---|---|---|---|
| **Component ID** | **Location** | **Description** | **Exam Type** | **Direct/ Remote** | **Comments** |
| | | | | | Augmented Examinations in accordance with IWE-1241. The items are coated. Available pictures of these components do not indicate any evidence of degradation of the square plates, weld, or the liner in the form of rusting, coating failure, or staining. No coating, weld, liner, or square metal plate degradation is identified in the inspection report. The surface areas are not subject to experiencing accelerated corrosion, degradation, or aging of the liner or coatings. The locations are not exposed to standing water, repeated wetting and drying, persistent leakage, water accumulation, condensation, or microbiological attack.<br>These areas are not subject to excessive wear from abrasion or erosion, which would cause a loss of protective coatings, deformation or material loss. |
| M-180/270 | 221' | Moisture Barrier Quadrant 180° to 270° Liner Shell at Embedment | E-A/E1.30 | Direct | RIS Item: 0°-360° Electrical conduit attached to containment liner by way of octagonal metal plates welded to the liner. These supports do not have welds on the horizontal or vertical plate to liner interface. Supports are located from 0° AZ to 360° AZ at all elevations.<br>Resolution:<br>The inaccessible surfaces behind the octagonal metal plates need not be subject to the Augmented Examinations in accordance with IWE-1241. The items are coated. The vertical and horizontal sides of the plate are caulked. Available pictures of these components do not indicate any evidence of degradation of the octagonal plates, weld, or the liner, in the form of rusting, coating or caulking failure or staining. No coating, weld, liner, or octagonal metal plate degradation is identified in the inspection report. The surface areas are not |

| Table 3.4.4-3, H1R21 Visual Examination of IWE Surfaces (VT-3) | | | | | |
|---|---|---|---|---|---|
| **Component ID** | **Location** | **Description** | **Exam Type** | **Direct/ Remote** | **Comments** |
| | | | | | subject to experiencing accelerated corrosion, degradation, or aging of the liner or coatings. The locations are not exposed to standing water, repeated wetting and drying, persistent leakage, water accumulation, condensation, or microbiological attack. These areas are not subject to excessive wear from abrasion or erosion, which would cause a loss of protective coatings, deformation or material loss. |
| | | | | | RIS Item: Elev. 286' - 0°-360° Vent Ductwork supports welded to containment liner. These supports have 1" of gap in weld in the center of the lower horizontal weld.<br>Resolution:<br>The items described are square plates welded to the liner with no components attached to the plates. Per the typical pad to shell weld detail, the weld is continuous around the plate, except for the gap in the lower horizontal weld. The inaccessible surfaces behind the square metal plates need not be subject to the Augmented Examinations in accordance with IWE-124·1. The items are coated. Available pictures of these components do not indicate any evidence of degradation of the square plates, weld, or the liner in the form of rusting, coating failure, or staining. No coating, weld, liner, or square metal plate degradation is identified in the inspection report. The surface areas are not subject to experiencing accelerated corrosion, degradation, or aging of the liner or coatings. The locations are not exposed to standing water, repeated wetting and drying, persistent leakage, water accumulation, condensation, or microbiological attack. These areas are not subject to excessive wear from abrasion or erosion, which would cause a loss of protective coatings, deformation or material loss. |

| Table 3.4.4-3, H1R21 Visual Examination of IWE Surfaces (VT-3) | | | | | |
|---|---|---|---|---|---|
| **Component ID** | **Location** | **Description** | **Exam Type** | **Direct/ Remote** | **Comments** |
| | | | | | 190°: 1/2" plastic tube in moisture barrier.<br>Resolution:<br>Tube is part of the design. No further action required. |
| | | | | | 210°, Recirc Sump 18, Top left corner: 1/2" hole in moisture barrier down to concrete interface.<br>Resolution:<br>This area is very small. No liner degradation was observed. No evidence of moisture intrusion. Repaired using RTV-732 Silicon caulking sealant. |
| | | | | | 234°, Recirc Sump 18, Top right corner: two small holes in moisture barrier. Moisture barrier is loose on the top of this corner and pulls away from the wall.<br>Resolution:<br>The area is very small. No liner degradation was observed. No evidence of moisture intrusion. Repaired using RTV-732 Silicon caulking sealant. |
| | | | | | 245°: 3 1/2" long crack with separation in moisture barrier.<br>Resolution:<br>Some deteriorated moisture barrier was observed at the liner interface. What appears to be a crack running between the liner and the concrete is actually a joint in the high density silicone elastomer (HDSE) material and not separation in the material. The HDSE material was continuous. No liner degradation was observed. The remaining moisture barrier below the defect was intact. No evidence of moisture intrusion. Repaired using HDSE by Promatec. |
| | | | | | 252°: 18" long area behind concrete wall with degraded moisture barrier, pulled away from liner.<br>Resolution: |

| Table 3.4.4-3, H1R21 Visual Examination of IWE Surfaces (VT-3) | | | | | |
|---|---|---|---|---|---|
| **Component ID** | **Location** | **Description** | **Exam Type** | **Direct/ Remote** | **Comments** |
| | | | | | No liner degradation was observed. No evidence of moisture intrusion. Repaired using RTV-732 Silicon caulking sealant. |
| M-270/360 | 221' | Moisture Barrier Quadrant 270° to 360° Liner Shell at Embedment | E-A/E1.30 | Direct | RIS Item Description: 0°-360° Electrical conduit attached to containment liner by way of octagonal metal plates welded to the liner. These supports do not have welds on the horizontal or vertical plate to liner interface. Supports are located from 0° AZ to 360° AZ at all elevations.<br>Resolution:<br>The inaccessible surfaces behind the octagonal metal plates need not be subject to the Augmented Examinations in accordance with IWE-1241. The items are coated. Per drawing 8-G-7205 S01 Detail “A”, the vertical and horizontal sides of the plate are caulked. Available pictures of these components do not indicate any evidence of degradation of the octagonal plates, weld, or the liner, in the form of rusting, coating or caulking failure or staining. No coating, weld, liner, or octagonal metal plate degradation is identified in the inspection report. The surface areas are not subject to experiencing accelerated corrosion, degradation, or aging of the liner or coatings. The locations are not exposed to standing water, repeated wetting and drying, persistent leakage, water accumulation, condensation, or microbiological attack. These areas are not subject to excessive wear from abrasion or erosion, which would cause a loss of protective coatings, deformation or material loss. |
| | | | | | RIS Item Description: Elev. 286' - 0°-360° Vent Ductwork supports welded to containment liner. These supports have 1" of gap in weld in the center of the lower horizontal weld.<br>Resolution: |

| Table 3.4.4-3, H1R21 Visual Examination of IWE Surfaces (VT-3) | | | | | |
|---|---|---|---|---|---|
| **Component ID** | **Location** | **Description** | **Exam Type** | **Direct/ Remote** | **Comments** |
| | | | | | The items described are square plates welded to the liner with no components attached to the plates. Per the typical pad to shell weld detail, the weld is continuous around the plate, except for the gap in the lower horizontal weld. The inaccessible surfaces behind the square metal plates need not be subject to the Augmented Examinations in accordance with IWE-1241. The items are coated. Available pictures of these components do not indicate any evidence of degradation of the square plates, weld, or the liner in the form of rusting, coating failure, or staining. No coating, liner, weld, or square metal plate degradation is identified in the inspection report. The surface areas are not subject to experiencing accelerated corrosion, degradation, or aging of the liner or coatings. The locations are not exposed to standing water, repeated wetting and drying, persistent leakage, water accumulation, condensation, or, microbiological attack. These areas are not subject to excessive wear from abrasion or erosion, which would cause a loss of protective coatings, deformation, or material loss. |
| | | | | | 280°: 1/2" plastic tube in moisture barrier.<br>Resolution:<br>Tube is part of design. No further action required. |
| | | | | | 320°, Top of Recirc Sump 1A: 5" gap in moisture barrier along liner. Resolution:<br>No liner degradation was observed. No evidence of moisture intrusion. Condition observed by IWE inspector. Repaired using RTV-732 Silicon caulking sealant. |
| LC-0/90 | 0-90, El. 221 ' to El. 376' | Containment Liner Plate Shell 0-90, El. 221 ' to El. 376' | E-A/E1.11 | Direct/Remote | 0°-360°: Minor chipping with no rusting or material loss in various areas at all elevations. No change from previous data. |
| | | | | | IWE 221' |

| Table 3.4.4-3, H1R21 Visual Examination of IWE Surfaces (VT-3) | | | | | |
|---|---|---|---|---|---|
| **Component ID** | **Location** | **Description** | **Exam Type** | **Direct/ Remote** | **Comments** |
| | | | | | 0° 10" up behind column, 3" wide by 2 1/2" high. Degraded coating, primer intact. No change from previous data.<br>0° Behind column, 8 1/2" wide by 3 1/2" high. Degraded coating, primer intact. No change from previous data.<br>43° Bulge. Noted in RFO16, no changes from previous data.<br>85°-95° Bulge. Noted in RFO16, no changes from previous data. |
| | | | | | IWE 261'<br>7° Bulge. Noted in RFO16, no changes from previous data.<br>85°-95° Bulge. Noted in RFO16, no changes from previous data. |
| LC-90/180 | 90-180, El. 221 ' to El. 376' | Containment Liner Plate Shell 90-180, El. 221 ' to El. 376' | E-A/E1.11 | Direct/Remote | 0°-360°: Minor chipping with no rusting or material loss in various areas at all elevations. No change from previous data. |
| | | | | | IWE 221'<br>115° Several conduit attachments stitch welded. Coating is degraded and showing signs of rust. No change from previous data.<br>120° Behind column, 10" wide by 3" high. Area is without coating or primer with moderate surface rust. No material loss noted. Area is marked on wall “For UT”.<br>120°-130° Bulge. Noted in RFO16, no changes from previous data.<br>130° 5' 1" up, 1 W' by 1 1/2" bare metal circle. No rusting noted. No change from previous data. |
| | | | | | IWE 261'<br>85°-95° Bulge. Noted in RFO16, no changes from previous data. |

| Table 3.4.4-3, H1R21 Visual Examination of IWE Surfaces (VT-3) | | | | | |
|---|---|---|---|---|---|
| **Component ID** | **Location** | **Description** | **Exam Type** | **Direct/ Remote** | **Comments** |
| | | | | | 180° 4'x4'x1" bulge at floor level. Engineering Change developed. |
| LC-180/270 | 180-270, El. 221 ' to El. 376' | Containment Liner Plate Shell 180-270, El. 221' to El. 376' | E-A/E1.11 | Direct/Remote | 0°-360°: Minor chipping with no rusting or material loss in various areas at all elevations. No change from previous data. |
| | | | | | IWE 261'<br>245°-256° Bulge. 10'x4' from elev. 275' to 281'. Noted in RFO16, no changes from previous data. |
| | | | | | IWE 261'<br>180° 4'x4'x1 " bulge at floor level. Engineering Change developed. |
| LC-270/360 | 270-360, El. 221 ' to El. 376' | Containment Liner Plate Shell 270-360, El. 221 ' to El. 376' | E-A/E1.11 | Direct/Remote | 0°-360° Minor chipping with no rusting or material loss in various areas at all elevations. No change from previous data. |
| | | | | | IWE 221'<br>0° 10" up behind column, 3" wide by 2 ½" high. Degraded coating, primer intact. No change from previous data.<br>0° Behind column, 8 ½" wide by 3 ½" high. Degraded coating, primer intact. No change from previous data. |
| S-6 | 260°/271' | Sleeve (30") S-6 - Mech. Pen. M-6 | E-A/E1.11 | Direct | The Coatings Program Manager and Paint Shop Supervisor have evaluated the degraded coatings conditions. These areas will be incorporated into the inspection results from Inspection of SL1 coatings inside RCB and repaired via WO. These types of coatings issues are not uncommon and can be expected each outage. The paint shop has a PM to perform routine touchups such as these in RCS. No additional evaluation is required. |
| S-4 | 280°/271' | Sleeve (30") S-4 - Mech. Pen. M-4 | E-A/E1.11 | Direct | The Coatings Program Manager and Paint Shop Supervisor have evaluated the degraded coatings conditions. These areas will be incorporated into the inspection results from Inspection of SL1 coatings inside RCB and repaired via WO. These types of coatings issues are not uncommon and can be expected each |

| Table 3.4.4-3, H1R21 Visual Examination of IWE Surfaces (VT-3) | | | | | |
|---|---|---|---|---|---|
| **Component ID** | **Location** | **Description** | **Exam Type** | **Direct/ Remote** | **Comments** |
| | | | | | outage. The paint shop has a PM to perform routine touchups such as these in RCS. No additional evaluation is required. |
| S-1 | 280°/278' | Sleeve (56") S-1 - Mech. Pen. M-1 | E-A/E1.11 | Direct | The Coatings Program Manager and Paint Shop Supervisor have evaluated the degraded coatings conditions. These areas will be incorporated into the inspection results from Inspection of SL1 coatings inside RCB and repaired via WO. These types of coatings issues are not uncommon and can be expected each outage. The paint shop has a PM to perform routine touchups such as these in RCS. No additional evaluation is required. |
| S-3 | 260°/278' | Sleeve (56") S-3 - Mech. Pen. M-3 | E-A/E1.11 | Direct | The Coatings Program Manager and Paint Shop Supervisor have evaluated the degraded coatings. These areas will be incorporated into the inspection results from Inspection of SL1 coatings inside RCB and repaired via WO. These types of coatings issues are not uncommon and can be expected each outage. The paint shop has a PM to perform routine touchups such as these in RCS. No additional evaluation is required. |

### 3.4.5 Containment Leakage Rate Testing Program – Type B and Type C Testing Program

The HNP Type B and C testing program requires testing of electrical penetrations, airlocks, hatches, flanges and CIVs in accordance with 10 CFR 50, Appendix J, Option A. 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 Type 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 6.8.4.k, the allowable maximum pathway total Type B and C leakage is 0.60 $L_a$ (101,200 standard cubic centimeters per minute (sccm)) where $L_a$ equals 168,800 sccm.

As discussed in NUREG-1493 (Reference 6), 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.

<u>As-Found Testing</u>
10 CFR 50, Appendix J, Option A does not require as-found testing for Type B and Type C penetrations.

Upon implementation of the proposed amendments to the HNP TS, as-found LLRT testing will be required in accordance with the requirements of NEI 94-01, Revision 3-A, Section 10.2.1 for Type B Test Intervals, and Section 10.2.3 for Type C Test Intervals.

<u>Type B and Type C Test Results</u>
A review of the as-left test values for HNP shows an average of 21.60% of 0.6 $L_a$ with a high of 33.57% of 0.6 $L_a$. This data shows that significant margin exists between the measured leakage and the allowed leakage on the Containment Building.

Table 3.4.5-1 provides LLRT data trend summaries for HNP since 2009 (the last ILRT was 2012).

**Table 3.4.5-1**
**HNP Unit 1 Types B and C LLRT Combined As-Left Trend Summary**

| **Outage & Year** | **H1R15 2009** | **H1R16 2010** | **H1R17 2012** | **H1R18 2013** | **H1R19 2015** | **H1R20 2016** | **H1R21 2018** |
|---|---|---|---|---|---|---|---|
| As-Left Max Path (sccm) | 16276 | 14266 | 15020 | 22221 | 20891 | 30446 | 33974 |
| Fraction of 0.6$L_a$ | 0.1608 | 0.1410 | 0.1484 | 0.2196 | 0.2064 | 0.3008 | 0.3357 |

As shown in Table 3.4.5-1 above, the record keeping requirements for HNP are different from those identified in other LARs requesting a permanent 15-year ILRT Interval with Containment Leakage Rate Testing Programs already following 10 CFR 50, Appendix J, Option B. 10 CFR 50,

Appendix J, Option A and ANSI/ANS 56.8-1987 are not performance-based regulations and standards.

The recordkeeping requirements found in 10 CFR 50, Appendix J, Option A, Section V.B.2 are associated with the Type A test only and are as stated below:

> For each periodic test, leakage test results from Type A, B, and C tests shall be included in the summary report. The summary report shall contain an analysis and interpretation of the Type A test results and a summary analysis of periodic Type B and Type C tests that were performed since the last type A test. Leakage test results from type A, B, and C tests that failed to meet the acceptance criteria of III.A.5(b), III.B.3, and III.C.3, respectively, shall be included in a separate accompanying summary report that includes an analysis and interpretation of the test data, the least squares fit analysis of the test data, the instrumentation error analysis, and the structural conditions of the containment or components, if any, which contributed to the failure in meeting the acceptance criteria. Results and analyses of the supplemental verification test employed to demonstrate the validity of the leakage rate test measurements shall also be included.

The requirements regarding as-found and as-left, and minimum and maximum pathway leakage rates, were not contained in ANSI/ANS 56.8-1987, hence they are also not reported in this LAR. With the adoption of 10 CFR 50, Appendix J, Option B, and NEI 94-01, Revision 3-A and the conditions and limitations of NEI 94-01, Revision 2-A as proposed in this LAR, the recording/reporting of as-found, as-left, minimum and maximum pathway leakage rates as stated in ANSI/ANS 56.8-2002 will become a requirement of the HNP Containment Leakage Rate Testing Program.

With the adoption of the proposed TS amendment, the recordkeeping requirements will reflect the following requirements:

10 CFR 50 Appendix J Option B, Section IV:

> The results of the preoperational and periodic Type A, B, and C tests must be documented to show that performance criteria for leakage have been met. The comparison to previous results of the performance of the overall containment system and of individual components within it must be documented to show that the test intervals established for the containment system and components within it are adequate. These records must be available for inspection at plant sites.

NEI 94-01 Revision 3-A, 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.

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

Table 3.4.6-1 (below) identifies HNP Unit 1 components which have not demonstrated acceptable performance during the previous two outages.

**Table 3.4.6-1**
**HNP Unit 1 Type B and C LLRT Program Implementation Review**

| **2016-H1R20** | | | | | | |
|---|---|---|---|---|---|---|
| **Component** | **As-found sccm** | **Admin Limit Alert / Action (sccm)** | **As-left (sccm)** | **Cause of Failure** | **Corrective Action (1)** | **Scheduled Interval** |
| M-7<br>1CS-7, -8, -9 | 11963 | 1200 | (2) | (2) | (2) | 18 months |
| M-78B<br>1SP-40 | 1647 | 300 | 24 | (3) | (3) | 18 months |
| M-83B<br>1SP-918 | >20,000 | 300 | 26 | (4) | (4) | 18 months |
| M-88<br>1SP-200 | 1503 | 300 | (5) | (5) | (5) | 18 months |
| **2018-H1R21** | | | | | | |
| **Component** | **As-found sccm** | **Admin Limit Alert /Action sccm** | **As-left sccm** | **Cause of Failure** | **Corrective Action (1)** | **Scheduled Interval** |
| M-105<br>1FP-349 | >20,000 | 1800 | 885 | (6) | Repacked drain valve 1FP-348. | 18 months |
| M-91<br>1SW-242 | >20,000 | 2400 | 1381 | (7) | Worked seat of 1SW-242. | 18 months |

| Table 3.4.6-1<br>HNP Unit 1 Type B and C LLRT Program Implementation Review | | | | | | |
|---|---|---|---|---|---|---|
| **2018-H1R21 (continued)** | | | | | | |
| **Component** | **As-found sccm** | **Admin Limit Alert /Action sccm** | **As-left sccm** | **Cause of Failure** | **Corrective Action (1)** | **Scheduled Interval** |
| M-88<br>1SP-201 | 4508/<br>4092 | 300 | (8) | (8) | Work 1SP-201 planned but not scheduled in H1R21. | 18 months |
| M-83A<br>1SP-16 | 1593 | 300 | (9) | (9) | Work 1SP-16 planned but not scheduled in H1R21. | 18 months |
| M-77A<br>1SI-290 | 660 | 300 | (10) | (10) | Work 1SI-290 planned but not scheduled in H1R21. | 18 months |
| M-77A<br>1SI-287 | 392 | 200 | (11) | (11) | Work 1SI-287 planned but not scheduled in H1R21. | 18 months |
| M-73A<br>1SP-915 | 14640 | 300 | 25 | (12) | Maintenance and retest satisfactory. | 18 months |
| M-9<br>1CS-344 | 23300 | 450 | 1994 | (13) | Maintenance and retest unsatisfactory. | 18 months |

Note 1: In the 10 CFR 50, Appendix J, Option A leak test program for Type B and C testing, the Acceptance Criteria is for the total leakage (summation of all penetration maximum pathway values). Individual valves and penetrations that exceed the listed Admin Limit Alert value listed in the Table may be placed back in service without maintenance, provided there is a measurable leak rate and that the total is within the Acceptance Criteria.

Note 2: Valves 1CS-7, -8, -9 had leakage in excess of the individual limit. The result was noted as unsatisfactory, was entered into the site corrective action program, and work requests (WR) were issued for repair (repairs were made during H1R21).

Under an Option A test program, this penetration was scheduled for testing in the next refueling outage. Testing was satisfactory during H1R21.

Note 3: Valves 1SP-40 had leakage in excess of the individual limit. The result was noted as unsatisfactory, was entered into the site corrective action program, and a WR were issued for repair. Work was performed and the valve retested satisfactorily.

Note 4: Valve 1SP-918 had excessive leakage past seat. WR issued to rework valve seat. Retest after maintenance was satisfactory.

Note 5: Valves 1SP-200 had leakage in excess of the individual limit. The result was noted as unsatisfactory, and WR exists to work on the valve. Under an Option A test program, this penetration was scheduled for testing in the next refueling outage. Testing was satisfactory during H1R21.

Note 6: During testing of component 1FP-349, found Drain Valve 1FP-348 had audible leakage from packing gland. Packing gland had no adjustment left in it. WR issued to repack valve. Retest after repacking was satisfactory.

Note 7: Valve 1SW-242 had excessive leakage past seat. WR issued to rework valve seat. Retest after maintenance was satisfactory.

Note 8: Valve 1SP-201 exceeded the acceptance criteria. WR issued to rework valve. Retest performed, but valve exhibited a higher than desired leak rate. The higher leak rate was evaluated against design requirements and accepted.

Note 9: Valve 1SP-16 exceeded the acceptance criteria. WR issued to rework valve. The higher leak rate was accepted.

Note 10: Valve 1SI-290 exceeded the acceptance criteria. WR issued to rework valve. The higher leak rate was accepted.

Note 11: Valve 1SP-287 exceeded the acceptance criteria. WR issued to rework valve. The higher leak rate was accepted.

Note 12: Valve 1SP-915 had excessive leakage. WR issued to rework valve. Retest after maintenance was satisfactory.

Note 13: Valve 1CS-344 had excessive leakage. WR issued to rework valve. Retest after maintenance was unsatisfactory. The leakage was evaluated and accepted.

**Repeat Failures**

Penetration M-88 recorded failures on one of the isolation valves in each of the last two outages. However, it was not the same valve in both outages. There was no repeat failure of a valve in this penetration. No other penetration or component showed failures in successive outages.

**Performance Summary**

Option A test programs for Type B and C LLRTs require that every penetration be tested each refueling outage. The lack of repeat failures and the leakage summary and margin to the allowable leakage indicates that the maintenance program is effective in providing a leak tight containment.

## 3.5 OPERATING EXPERIENCE (OE)

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 HNP primary containment, the following site specific and industry events have been evaluated for impact:

- IN 1992-20, “Inadequate Local Leak Rate Testing”
- IN 2014-07, “Degradation of Leak-Chase Channel Systems for Floor Welds of Metal Containment Shell and Concrete Containment Metallic Liner”
- IN 2004-09, “Corrosion of Steel Containment and Containment Liners”
- IN 2010-12, “Containment Liner Corrosion”
- RIS 2016-07, “Containment Shell or Liner Moisture Barrier Inspection”

Each of these areas are discussed in detail in Sections 3.5.1 through 3.5.5, respectively.

### 3.5.1 IN 1992-20, 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 Nuclear Power Station, Dresden Nuclear Station, Perry Nuclear Power Plant, and the Clinton Station. Specifically, LLRTs could not be relied upon to accurately measure the leakage rate that would occur under accident conditions because, during testing, the two plies in the bellows were in contact with each other, restricting the flow of the test medium to the crack locations. Any two-ply bellows of similar construction may be susceptible to this problem. 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

IN 1992-20 is not applicable to HNP, as HNP does not utilize this type of bellows assembly in the plant. Additionally, all valves at HNP are evaluated for proper testing (i.e., tested in the accident direction) or are evaluated for testing between the valves (e.g., Purge Exhaust Valves). HNP does not take credit for any water seals in its LLRT program.

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

This IN addresses concerns identified by the NRC for degradation of floor weld leak-chase channel systems of steel containment shell and concrete containment metallic liners that could affect leak-tightness and aging management of containment structures. This IN also explicitly states the NRC's interpretation that leak chase channels should be considered a moisture barrier as defined in ASME Section XI, Subsection IWE.

Although this IN required no specific actions or written responses, it was evaluated under HNP's corrective action program.

All of the test channels at HNP that are on the bottom of the containment liner have been completely encapsulated in concrete (under the base mat). As such, these are protected by the moisture barrier around containment just as the rest of the concrete-inaccessible parts of the liner. At the edges of containment, as the test channels lead upwards, they do not lead to ports in the floor of the concrete base mat to be covered by floor plates, unlike those referenced in the IN. Any exposed pressurization ports for the test channels are on the walls of containment at least 12" above the base mat.

Due to no leak chase test channel ports being located through the base mat or at floor-level, the degradation mechanism identified in this IN is not applicable at HNP. The only possible degradation path for the concrete-inaccessible part of the containment liner is around the edges of containment, which is protected via the moisture barrier that is in-place and inspected every period.

### 3.5.3 IN 2004-09, Corrosion of Steel Containment and Containment Liner

This IN addresses concerns identified by the NRC for corrosion in freestanding metallic containments and in liner plates of reinforced and pre-stressed concrete containments. This IN states, “As discussed in Information Notice 97-10, “Liner Plate Corrosion in Concrete Containments,” the containment liners have safety factors well above the theoretically calculated strains. 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.”

HNP performed an extensive evaluation of this IN, having discovered corrosion on the liner interior surface of the containment in the vicinity of its interface with the concrete base mat in May 1997 during RFO7. The evaluation concluded that based on the evaluation of data collected during RFO7, RFO8 and subsequent visual examinations performed in accordance with ASME Section XI, Subsection IWE, the following conclusions can be drawn:

- The thickness of the containment liner at locations near the seal is well above the minimum required thickness determined by design calculations.
- There is no evidence that liner corrosion is progressing at or near the seal.

The repairs that were made to the seal and to the areas of the liner which exhibited corrosion have been effective in preventing the development of additional corrosion. In addition, the repairs, modifications, and procedural changes made to the containment recirculation sumps have prevented further intrusion of water into the gap between the liner and the base mat.

The steel liner is examined periodically per IWE requirements. The seal area is monitored each refueling outage by examination and a preventative maintenance activity to attempt to draw water from the gap between the liner and the base mat.

It was determined that existing programs and practices provide sufficient barriers to prevent similar occurrences. The evaluations performed subsequent to the initial observation of liner corrosion thoroughly addressed the condition and the corrective measures to prevent reoccurrence. The IWE examination program, the SL1 Coatings program, and the required examination prior to Type A testing are sufficient to identify future degradation of the liner.

### 3.5.4 IN 2010-12, Containment Liner Corrosion

The NRC issued this IN to inform addressees of recent issues involving corrosion of the steel reactor containment building liner, providing examples from three different units.

Concrete reactor containments are typically lined with a carbon steel liner to ensure a high degree of leak tightness during operating and accident conditions. Operating experience shows that containment liner corrosion is often the result of liner plates being in contact with objects and materials that are lodged between or embedded in the containment concrete. Liner locations that are in contact with objects made of an organic material are susceptible to accelerated corrosion because organic materials can trap water that combined with oxygen will promote carbon steel corrosion. Organic materials can also cause a localized low pH area when they decompose. Organic materials located inside containment can come in contact with the containment liner and cause accelerated corrosion. However, corrosion that originates between the liner plate and concrete is of a greater concern because visual examinations typically identify the corrosion only after it has significantly degraded the liner. In some cases, licensees identified such corroded areas by performing ultrasonic examination of suspect areas (e.g., areas of obvious bulging, hollow sound).

Duke Energy's evaluation of this OE concluded that it is applicable to HNP as the HNP containment has a steel liner. It also noted that the Containment IWE-IWL Program and examination procedure contain steps to perform visual examinations for corrosion of the steel liner and identify liner bulge areas.

### 3.5.5 RIS 2016-07, Containment Shell or Liner Moisture Barrier Inspection

The NRC issued this RIS to reiterate the NRC staff's position in regard to inservice inspection requirements for moisture barrier materials as discussed in the ASME B&PV Code, Section XI, Subsection IWE. The RIS 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 E.130. Note 4 (Note 3 in editions before 2013) for Item E1.30 under the "Parts Examined" column states that "Examinations 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."

Examples of inadequate inspections have included licensees not identifying sealant materials at metal-to-metal interfaces as moisture barriers because they do not specifically match Figure IWE-2500-1, and licensees not inspecting installed moisture barrier materials, as required by Item E1.30, because the material was not included in the original design or was not identified as a "moisture barrier" in design documents.

Duke Energy's evaluation of RIS 2016-07 as applied to HNP resulted in the development of the following three actions:

A1. Identify all specific locations within each containment where the following conditions exist:

- Back-to-back metal interfaces at the containment shell (interior and exterior surfaces) or liner (interior surfaces only) that are not seal-welded (e.g., baseplates, stitch-welded attachments). For each of these, identify and document whether any moisture barrier material exists, and the configuration and type of moisture barrier present, including any coatings that seal the interface.
- Interfaces between the containment shell (interior and exterior surfaces) or liner (interior surfaces only) and any adjacent concrete (e.g., embedment zones, interior floor or wall interfaces) where the existence of concrete or other materials (e.g., expansion joint material) prevents visual examination of any containment shell or liner metallic surface beyond the interface. For each of these, identify and document whether any moisture barrier material exists, and the configuration and type of moisture barrier present, including any coatings that seal the interface.
- Expansion joints and other concrete-to-concrete interfaces in concrete floors placed directly over/on the interior surfaces of the containment liner plate. For each of these, identify and document whether any moisture barrier material exists, and the configuration and type of moisture barrier present, including any coatings that seal the interface.

A2. For all locations identified above where there is no moisture barrier present, or where the condition of any moisture barrier has degraded such that moisture intrusion behind the joint could occur if the joint is exposed to water, take one of the following actions:

- Install a moisture barrier and revise the Inservice Inspection Plan to document the location of the moisture barrier. Schedule the item for examination in accordance with Table IWE-2500-1, Examination Category E-A, Item E1.30.
- Document the basis for why inaccessible surfaces of the containment shell or liner behind the specific location are not subject to Augmented Examination in accordance with IWE-1241 in the Inservice Inspection Plan (or in another document that shall be maintained as a QA Record and can be referenced in the Inservice Inspection Plan).
- Revise the Inservice Inspection Plan to document the location of each interface and schedule the affected item (moisture barrier) for augmented examination in accordance with IWE-1242 and Table IWE-2500-1, Examination Category E-C, Item E4.11 or E4.12, as applicable.

A3. Verify that procedures for performing Table IWE-2500-1, Examination Category E-A, Item E1.30 examinations contain sufficient information pertaining to the scope (examination boundary) and acceptance standards for visual examination of all types of moisture barriers at each site. Generate a procedure revision request for any procedure used for visual examination of moisture barriers if the scope or acceptance standards are not clear.

All actions detailed in A.1, A.2, and A.3 above were performed during HNP Refueling Outage H1R21 (Spring 2018) and all damaged areas were resealed.

### 3.6 LICENSE RENEWAL AGING MANAGEMENT

HNP FSAR Chapter 18, "Final Safety Analysis Report Supplement for License Renewal," contains the FSAR Supplement as required by 10 CFR 54.21(d) for the HNP License Renewal Application (LRA). The NRC issued the HNP, Unit 1 SER via NUREG-1916, "Safety Evaluation Report Related to the License Renewal of Shearon Harris Nuclear Power Plant, Unit 1" (Reference 21). The renewed operating license for HNP, Unit 1 was issued on August 20, 2008, extending the original licensed operating term by 20 years. HNP Unit 1 will enter the period of extended operation on October 24, 2026.

The aging management activity descriptions presented in Chapter 18 of the FSAR represent commitments for managing aging of the in-scope systems, structures and components during the period of extended operation. As part of the license renewal effort, it had to be demonstrated that the aging effects applicable for the components and structures within the scope of license renewal would be adequately managed during the period of extended operation.

The following programs/activities are credited with the aging management of the primary containment:

- <u>FSAR 18.1.1.29, 10 CFR 50, Appendix J Program</u>

  The 10 CFR Part 50, Appendix J Program is an existing program that consists of monitoring of leakage rates through containment liner/welds, penetrations, fittings, and access openings to detect degradation of the pressure boundary. An evaluation is performed and appropriate corrective actions are taken if leakage rates exceed acceptance criteria. For the ILRT, this Program is implemented in accordance with Option B (performance-based leak testing) of 10 CFR 50 Appendix J, RG 1.163, and NEI 94-01. For LLRT, the Program is currently in accordance with the prescriptive requirements of 10 CFR Part 50, Appendix J Option A, pending the changes proposed in this LAR.

  Prior to the period of extended operation, the program will be enhanced to describe in the implementing procedures the evaluation and corrective actions to be taken when leakage rates do not meet their specified acceptance criteria. Following enhancement, the Program will be consistent with the corresponding program described in NUREG-1801.

- <u>FSAR 18.2.4.1, Mechanical Penetration Bellows – Valve Chambers</u>

  The four mechanical penetration bellows addressed by this section are the Containment Spray and Safety Injection System Recirculation Valve Chamber Bellows associated with containment penetrations M-47 through M-50. Per the plant specifications, the valve chamber bellows expansion joint design is in accordance with ASME Section III, Paragraph NC-3649.1 so that no single corrugation is permitted to deflect more than its maximum allowable amount.

Each bellows is designed to withstand a total of 7,000 cycles of expansion and compression over its lifetime due to maximum normal operating conditions plus 10 cycles of movement due to safe shutdown earthquake condition.

Operating cycles of expansion and compression due to maximum normal operating conditions was calculated by adding the number of containment cycles corresponding to RCS heat-up and cooldown cycles plus the number of times the containment is pressurized during Type A Integrated Leak Rate Testing (ILRT) plus the number times a Type B local leak rate test (LLRT) is performed.

The expansion bellows is the barrier between the valve chamber and the Reactor Auxiliary Building. The CIVs associated with these chambers isolate the containment sumps from the CS and RHR Systems and, therefore, do not normally experience any fluid flow.

Operation of RHR during cool-down of the RCS would have a negligible impact on the bellows due to the piping configuration but are included since operation of RHR would typically correspond to the RCS (Class 1) cycles.

The number of Reactor Thermal Cycles projected over 60 years is 81 cycles. The containment ILRT is performed infrequently (i.e., currently once every 10 years). Conservatively, assuming an ILRT will be performed once every 5 years rather than the maximum period of 10 years yields 12 cycles. Per Type B LLRT program, the maximum test interval for this equipment is 24 months. Since this is the maximum interval, the minimum will be conservatively assumed to be yearly resulting in an additional 60 cycles. The total number of cycles anticipated for 60 years is as follows:

81 + 12 + 60 = 153 cycles.

Since the total number of thermal cycles for the CS and Safety Injection System Recirculation Valve Chamber Bellows is less than 7,000 cycles, no re-analysis of the design calculations is necessary. Therefore, the CS and Safety Injection System Recirculation Valve Chamber Bellows design analyses of record remain valid for the period of extended operation.

- FSAR 18.1.1.26, ASME Section XI, Subsection IWE Program

  The ASME Section XI, Subsection IWE Program is an existing aging management program used for the aging management of accessible and inaccessible pressure retaining Containment Structure Class MC components. The HNP program is implemented in accordance with the requirements of 10 CFR 50.55a and the applicable Edition and Addenda of the ASME B&PV Code, Section XI, as required by 10 CFR 50.55a(g)(4)(ii).

  Prior to the period of extended operation, the ASME Section XI, Subsection IWE Program implementing procedure will be enhanced to: (1) include additional recordable conditions, (2) include moisture barrier and applicable aging effects, (3) include pressure retaining bolting and aging effects, and (4) include a discussion of augmented examinations.

- FSAR 18.1.1.27, ASME Section XI, Subsection IWL Program

  The ASME Section XI, Subsection IWL Program is an existing aging management program used for the aging management of accessible and inaccessible pressure retaining Primary Containment concrete. The HNP containment structure does not use prestressing tendons. Therefore, ASME Section XI, Subsection IWL rules regarding post-tensioning systems are not applicable. The HNP program is implemented in accordance with the requirements of 10 CFR 50.55a and the applicable Edition and Addenda of the ASME B&PV Code, Section XI, as required by 10 CFR 50.55a(g)(4)(ii).

- FSAR 18.1.1.31, Structures Monitoring Program

  The Structures Monitoring Program consists of periodic inspection and monitoring of the condition of structures and structure component supports to ensure that aging degradation leading to loss of intended functions will be detected and that the extent of degradation can be determined. It is an existing program that is implemented in accordance with the Maintenance Rule (10 CFR 50.65), NEI 93-01, “Industry Guidelines for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” and RG 1.160, “Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.” The inspection criteria are based on American Concrete Institute Standard ACI 349.3R-96, “Evaluation of Existing Nuclear Safety-Related Concrete Structures,” American Society of Civil Engineers Standard ASCE 11-90, “Guideline for-Structural Condition Assessment of Existing Buildings,” Institute for Nuclear Power Operations (INPO) Good Practice document 85-033, “Use of System Engineers,” and NEI 96-03, “Guidelines for Monitoring the Condition of Structures at Nuclear Plants.”

  Prior to the period of extended operation, the Structures Monitoring Program implementing procedures will be enhanced to: (1) identify the License Renewal structures and systems that credit the program for aging management; (2) require notification of the responsible engineer when below-grade concrete is exposed so an inspection may be performed prior to backfilling; (3) require periodic groundwater chemistry monitoring including consideration for potential seasonal variations; (4) define the term “structures of a system” in the system walkdown procedure and specify the condition monitoring parameters that apply to “structures of a system;” (5) include the corporate structures monitoring procedure as a reference in the plant implementing procedures and specify that forms from the corporate procedure be used for inspections; (6) identify additional civil/structural commodities and associated inspection attributes required for License Renewal; and (7) require inspection of inaccessible surfaces of reinforced concrete pipe when exposed by removal of backfill. Following enhancement, the Structures Monitoring Program will be consistent with the corresponding program described in NUREG-1801.

## 3.7 NRC SER LIMITATIONS AND CONDITIONS

### 3.7.1 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 3.7.1-1 are satisfied:

**Table 3.7.1-1**
**NEI 94-01, Revision 2-A Limitations and Conditions**

| Limitation/Condition (From Section 4.0 of SE, Reference 8) | HNP 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.) | HNP 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 (Tables 3.4.2-1, 3.4.2-2, 3.4.2-3 and 3.4.2-4) of this LAR submittal. |
| The licensee addresses the areas of the containment structure potentially subjected to degradation. (Refer to SE Section 3.1.3.) | Reference Section 3.4.2 (Tables 3.4.2-5, and 3.4.2-6) of this LAR submittal. |
| The licensee addresses any tests and inspections performed following major modifications to the containment structure, as applicable. (Refer to SE Section 3.1.4.) | HNP removed and re-welded the equipment hatch in 2001 to support SGR. HNP is removing and re-welding the equipment hatch in support of reactor pressure vessel head replacement during the Fall 2019 refueling outage. Reference Section 3.1.3 of this submittal. |

**Table 3.7.1-1**
**NEI 94-01, Revision 2-A Limitations and Conditions**

| Limitation/Condition (From Section 4.0 of SE, Reference 8) | HNP Response |
|---|---|
| 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.) | HNP 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.<br><br>In accordance with the requirements of NEI 94-01, Revision 2-A, SER Section 3.1.1.2, HNP 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. HNP was not licensed under 10 CFR Part 52. |

### 3.7.2 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 of the optional performance-based requirements of Option B to 10 CFR 50, Appendix J. However, the NRC staff identified two conditions on the use of NEI TR 94-01, Revision 3 in the associated SER (Reference 2):

*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 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 the following three (3) separate issues that are required to be addressed:

- 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 with exceptions as detailed in NEI 94-01, Revision 3-A, Section 10.1.

*Response to Condition 1, ISSUE 1*

The post-outage report shall include the margin between the Type B and Type C 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 HNP administrative leakage summation limit of 0.5 $L_a$, 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 HNP 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*

HNP 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 is 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 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 leakage, 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 the following two (2) separate issues that are required to be addressed:

- 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 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, HNP 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 (i.e., 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 HNP administrative 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 HNP leakage limit. The corrective action plan should 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 HNP administrative 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 HNP, 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 HNP, an adverse trend is defined as three consecutive increases in the final pre-mode change Type B and C MNPLR leakage summation values, as adjusted to include the estimate of applicable Type C leakage understatement, as expressed in terms of $L_a$.

### 3.8 CONCLUSION

NEI 94-01, Revision 3-A, dated July 2012, and the limitations and conditions specified in NEI 94-01, Revision 2-A, dated October 2008, describe an NRC-accepted approach for implementing the performance-based requirements of 10 CFR 50, Appendix J, Option B. It incorporates the regulatory positions stated in RG 1.163 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. HNP is adopting the guidance of NEI 94-01, Revision 3-A, and the limitations and conditions specified in NEI 94-01, Revision 2-A, for the HNP, 10 CFR 50, Appendix J testing program plan.

Based on the previous ILRTs conducted at HNP, Duke Energy concludes 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 HNP inspection programs:

- Containment Inservice Inspection Program (IWE)
- Containment Inservice Inspection Program (IWL)
- Protective Coatings Program

This experience is supplemented by risk analysis studies, including the HNP risk analysis provided in Attachment 3 of this submittal. The risk assessment concludes that increasing the ILRT interval on a permanent basis to a one-in-fifteen-year frequency is not considered to be significant because it represents only a small change in the HNP 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, Leakage Rate Testing of Containment of Water Cooled Nuclear Power Plants. Appendix J specifies containment leakage testing requirements, including the types required to ensure the leak-tight integrity of the primary reactor containment and systems and components which penetrate the containment. In addition, Appendix J discusses leakage rate acceptance criteria, test methodology, frequency of testing and reporting requirements for each type of test.

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

EPRI TR-1009325, Revision 2-A (Reference 11), provided a risk impact assessment for optimized ILRT intervals up to 15 years, utilizing current industry performance data and risk informed guidance. NEI 94-01, Revision 3-A, Section 9.2.3.1 (Reference 2), states that Type A ILRT intervals of up to 15 years are allowed by this guideline. The Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals, EPRI Report 1018243 (formerly TR-1009325, Revision 2-A) (Reference 11), 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 (Reference 30), and the modified testing frequencies recommended by NEI TR 94-01, Revision 2, serve to ensure continued leakage integrity of the containment structure. Type B and Type C testing ensures that individual penetrations are essentially leak tight. In addition, aggregate Type B and Type C leakage rates support the leakage tightness of primary containment by minimizing potential leakage paths.

For EPRI Report No. 1009325, Revision 2, a risk-informed methodology using plant-specific risk insights and industry ILRT performance data to revise ILRT surveillance frequencies, the NRC staff finds that the proposed methodology satisfies the key principles of risk-informed decision making applied to changes to TS as delineated in RG 1.174 (Reference 3) and RG 1.177 (Reference 34), "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications." The NRC staff, therefore, found that this guidance was acceptable for referencing by licensees proposing to amend their TS in regard to containment leakage rate testing, subject to the limitations and conditions noted in Section 4.2 of the SER.

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

### 4.2 Precedent

This LAR is similar in nature to the following license amendments to extend the Type A Test Frequency to 15 years and the Type C test frequency to 75 months as previously authorized by the NRC in the associated referenced SERs:

- Beaver Valley Power Station, Unit Nos. 1 and 2 (Reference 22)
- Calvert Cliffs Nuclear Power Plant, Unit Nos. 1 and 2 (Reference 23)
- Comanche Peak Nuclear Power Plant, Units 1 and 2 (Reference 26)

Additionally, this LAR is similar in nature to the H. B. Robinson Steam Electric Plant, Unit No. 2 license amendment (Reference 27) as previously authorized by the NRC to adopt Option B of 10

CFR 50, Appendix J, as modified by approved exemptions, for the performance-based testing of Type B and Type C tested components in accordance with TSTF-52, Revision 3.

### 4.3 No Significant Hazards Consideration

Duke Energy Progress, LLC (Duke Energy) has proposed an amendment to the Shearon Harris Nuclear Power Plant, Unit 1 (HNP) Technical Specifications (TS). This amendment will 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 Part 50, Appendix J," Revision 3-A (Reference 2), and the conditions and limitations specified in NEI 94-01, Revision 2-A (Reference 8). The amendment will replace the commitment to 10 CFR 50 Appendix J, Option A for Type B and Type C testing with the adoption of 10 CFR 50, Appendix J, Option B, as modified by approved exemptions, for the performance-based testing of Type B and C tested components in accordance with the guidance of Technical Specification Task Force (TSTF)-52, "Implement 10 CFR 50, Appendix J, Option B" (Reference 44). The amendment will also 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. In addition, the amendment adopts 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. This license amendment request (LAR) also proposes an administrative change to TS 6.8.4.k to delete the information regarding the performance of the next HNP Type A test to be performed no later than May 23, 2012, as this Type A test has already occurred.

Duke Energy has evaluated whether or not a significant hazards consideration is involved with the proposed amendment to the HNP TS by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

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

   Response: No.

   The proposed amendment to the HNP TS involves the extension of the Type A containment test interval to 15 years, the extension of the Type B test intervals to 120 months for selected components, and the extension of the Type C test interval to 75 months for selected components. 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 amendment will also replace the commitment to 10 CFR 50 Appendix J, Option A for Type B and Type C testing with the adoption of 10 CFR 50, Appendix J, Option B, as modified by approved exemptions, for the performance-based testing of Type B and C tested components, including the associated TS changes, in accordance with the guidance of TSTF-52.

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 0.038 person-rem/year for HNP. The 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 integrated leakage rate test (ILRT) intervals. Moreover, the risk impact when compared to other severe accident risks is negligible. Therefore, this proposed extension does not involve a significant increase in the probability of an accident previously evaluated.

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

The integrity of the containment is subject to two types of failure mechanisms that can be categorized as: (1) activity-based, and (2) time-based. Activity-based failure mechanisms are defined as degradation due to system and/or component modifications or maintenance. The local leak rate testing (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 an exception previously granted to allow a one-time extension of the ILRT test frequency at HNP Unit 1. This exception was for an activity that has already taken place, so the 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 changes do 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 TS 6.8.4.k involves the extension of the HNP Type A containment test interval to 15 years, the Type B test interval to 120 months for selected components, and the extension of the Type C test interval to 75 months for selected components. The change will also replace the commitment to 10 CFR 50 Appendix J, Option A for Type B and Type C testing with the adoption of 10 CFR 50, Appendix J, Option B, as modified by approved exemptions, for the performance-based testing of Type B and C tested components, including the associated TS changes, in accordance with the guidance of TSTF-52.

   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 changes do 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 an exception previously granted to allow one-time extension of the ILRT test frequency at HNP. This exception was for an activity that has already taken place, so the 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 changes do 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 6.8.4.k involves the extension of the HNP Type A containment test interval to 15 years, the Type B test interval to 120 months for selected components, and the extension of the Type C test interval to 75 months for selected components. The change replaces the commitment to 10 CFR 50 Appendix J, Option A for Type B and Type C testing with the adoption of 10 CFR 50, Appendix J, Option B, as modified by approved exemptions, for the performance-based testing of Type B and C tested components, including the associated TS changes, in accordance with the guidance of TSTF-52.

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 the extension of the interval between Type A containment leak rate tests, Type B tests and Type C tests for HNP. The proposed surveillance interval extension is bounded by the 15-year ILRT interval, the 120-month Type B 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 TS 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, Type B and Type C test intervals.

The proposed amendment also deletes an exception previously granted to allow one-time extension of the ILRT test frequency at HNP. This exception was for an activity that has already taken place, so the deletion is solely an administrative action that has no effect on any component and no impact on how the unit is operated. Thus, there is no reduction in any margin of safety as a result of this administrative change.

Therefore, the proposed changes do not involve a significant reduction in a margin of safety.

Based on the above, Duke Energy 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

Duke Energy 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. RG 1.163, Performance-Based Containment Leak-Test Program, September 1995 (ADAMS Accession No. ML003740058)

2. NEI 94-01, Revision 3-A, Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J, July 2012 (ADAMS Accession No. ML12221A202)

3. RG 1.174, Revision 2, An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis, May 2011 (ADAMS Accession No. ML100910006)

4. RG 1.200, Revision 2, An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities, March 2009 (ADAMS Accession No. ML090410014)

5. NEI 94-01, Revision 0, Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J, dated July 21, 1995 (ADAMS Accession No. ML11327A025)

6. NUREG-1493, Performance-Based Containment Leak-Test Program – Final Report, September 1995 (ADAMS Accession No. 9510200161)

7. Electric Power Research Institute (EPRI) Topical Report No. 104285, Risk Impact Assessment of Revised Containment Leak Rate Testing Intervals, Palo Alto, California, August 1994

8. NEI 94-01, Revision 2-A, Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J, October 2008 (ADAMS Accession No. ML100620847)

9. 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 (ADAMS Accession No. ML081140105)

10. 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 (ADAMS Accession No. ML121030286)

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

12. Letter from NRC (R. J. Laufer) to Carolina Power & Light Company (J. Scarola), Issuance of Amendment No. 91 – Shearon Harris Nuclear Power Plant, Unit 1 (TAC No. MA5944), dated September 17, 1999 (ADAMS Accession No. ML020600010)

13. Letter from NRC (R. J. Laufer) to Carolina Power & Light Company (C. J. Gannon), Issuance of Amendment No. 122 – Shearon Harris Nuclear Power Plant, Unit 1 (TAC No. MC6722), dated March 30, 2006 (ADAMS Accession No. ML060720228)

14. Letter from NRC (N. Kalyanam) to Carolina Power & Light Company (J. Scarola), Issuance of Amendment No. 107 - Steam Generator Replacement and Power Uprate (TAC Nos. MB0199 and MB0782), dated October 12, 2001 (ADAMS Accession No. ML012830516)

15. Letter from Duke Energy Progress, LLC (T. M. Hamilton) to NRC (Document Control Desk), Shearon Harris Nuclear Power Plant, Unit 1 - Relief Request I3R-18, Alternative Repair and Replacement Testing Requirements for the Containment Building Equipment Hatch Sleeve Weld, Inservice Inspection Program for Containment, Third Ten-Year Interval, dated June 4, 2018 (ADAMS Accession No. ML18156A026)

16. Letter from NRC (U. Shoop) to Duke Energy Progress, LLC (T. Hamilton), Shearon Harris Nuclear Power Plant, Unit 1 – Relief Request I3R-18, Regarding Alternative Repair and Replacement Testing Requirements for the Containment Building Equipment Hatch Sleeve Weld, Inservice Inspection Program for Containment, Third Ten-Year Interval (EPID L-2018-LLR-0081), dated February 26, 2019 (ADAMS Accession No. ML19018A025)

17. NEI 07-12, Fire Probabilistic Risk Assessment (FPRA) Peer Review Process Guidelines, Revision 1, June 2010 (ADAMS Accession No. ML102230070)

18. Containment Liner Corrosion Operating Experience Summary, Technical Letter Report – Revision 1, by D. S. Dunn, A. L. Pulvirenti, and M. A. Hiser (Office of Nuclear Regulatory Research - NRC), dated August 2, 2011 (ADAMS Accession No. ML112070867)

19. 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

20. RG 1.200, Revision 0, An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities, February 2004 (ADAMS Accession No. ML040630078)

21. NUREG-1916, Safety Evaluation Report Related to the License Renewal of Shearon Harris Nuclear Power Plant, Unit 1, Docket No. 50-400, Volume 1 Published November 2008 (ADAMS Accession Nos. ML090050172 and ML090060737)

22. Letter from NRC (T. A. Lamb) to FirstEnergy 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 (ADAMS Accession No. ML15078A058)

23. Letter from NRC (A. N. Chereskin) to Exelon Generation Company, LLC (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 (ADAMS Accession No. ML15154A661)

24. NEI 00-02, Probabilistic Risk Assessment (PRA) Peer Review Process Guidance Rev. A3, PSA Peer Review Enclosures, dated March 20, 2000 (ADAMS Accession No. ML003728023)

25. ASME/ANS, Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications, ASME/ANS RA-Sa-2009, dated March 2009. Addendum A to RA-S-2008

26. Letter from NRC (B. K. Singal) to Luminant Generation Co. (R. Flores), 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 (CAC Nos. MF5621 and MF5622), dated December 30, 2015 (ADAMS Accession No. ML15309A073)

27. Letter from NRC (D. J. Galvin) to Duke Energy Progress, LLC (R. M. Glover), H. B. Robinson Steam Electric Plant, Unit No. 2 – Issuance of Amendment to Extend Containment Leakage Rate Test Frequencies (CAC No. MF7102), dated October 11, 2016 (ADAMS Accession No. ML16201A195)

28. RG 1.54, Revision 0, Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants, June 1973 (ADAMS Accession No. ML003740187)

29. Letter from Entergy Operations, Inc. (K. Mulligan) to NRC (Document Control Desk), Grand Gulf Nuclear Station Response to Request for Additional Information Regarding License Amendment Request to Revise Technical Specifications for Containment Leak Rate Testing, Grand Gulf Nuclear Station, Unit 1, Docket No. 50-416, License No. NPF-29, (GNRO-2015/00063), dated October 28, 2015 (ADAMS Accession No. ML15302A042)

30. American Nuclear Society, ANSI/ANS 56.8-2002, "Containment System Leakage Testing Requirements," LaGrange Park, Illinois, November 2002

31. ASME B&PV Code, Section XI, Subsection IWE, Requirements for Class MC and Metallic Liners of Class CC Components of Light-Water Cooled Plants

32. ASME B&PV Code, Section XI, Subsection IWL, Requirements for Class CC Concrete Components of Light-Water Cooled Plant

33. RG 1.147, Inservice Inspection Code Case Acceptability, ASME Section XI, Division 1, Revision 17, August 2014 (ADAMS Accession No. ML13339A689)

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

35. ASME/ANS, Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications, ASME/ANS RA-Sb-2009, dated March 2009. Addendum B to RA-S-2008

36. Letter from NRC (M. Barillas) to Duke Energy Progress, LLC (T. Hamilton), Shearon Harris Nuclear Power Plant, Unit 1 – Issuance of Amendment Regarding Risk-Informed Justifications for the Relocation of Specific Surveillance Frequency Requirements to a Licensee-Controlled Program (CAC No. MF6583), November 29, 2016 (ADAMS Accession No. ML16200A285)

37. Letter from NRC (M. Vaaler) to Carolina Power & Light Company (C. Burton), Shearon Harris Nuclear Power Plant, Unit 1 – Issuance of Amendment Regarding Adoption of National Fire Protection Association Standard 805, "Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants," June 28, 2010 (ADAMS Accession Nos.

ML101750602 and ML101750604)

38. NUREG-2122, Glossary of Risk-Related Terms in Support of Risk-Informed Decision Making, November 2013 (ADAMS Accession No. ML13311A353)

39. RG 1.174, Revision 3, An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis, January 2018 (ADAMS Accession No. ML17317A256)

40. Letter from Constellation Nuclear (C.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, March 27, 2002 (ADAMS Accession No. ML020920100)

41. Report 025114-RPT-01, “Shearon Harris Nuclear Power Plant Fire PRA Focused-Scope Peer Review,” Revision 0, June 2019

42. Letter from NRC (J. Giitter and M. Ross-Lee) to NEI (Greg Krueger), U.S. Nuclear Regulatory Commission Acceptance on Nuclear Energy Institute Appendix X to Guidance 05-04, 7-12, and 12-13, Close Out of Facts and Observations (F&Os), May 3, 2017, (ADAMS Accession No. ML17079A427)

43. Report 25114-RPT-02, “Shearon Harris Nuclear Power Plant PRA Fact and Observation Independent Assessment,” Revision 0, June 2019

44. Industry/TSTF Standard Technical Specification Change Traveler TSTF-52, “Implement 10 CFR 50, Appendix J, Option B,” Revision 3 (ADAMS Accession No. ML040400371)

45. Letter from NRC (M. Barillas) to Duke Energy Progress, LLC (T. Hamilton), Shearon Harris Nuclear Power Plant, Unit 1 – Issuance of Amendment No. 174 RE: Adopt Title 10 of the Code of Federal Regulations 50.69, “Risk-Informed Categorization and Treatment of Structures, Systems, and Components (SSCs) for Nuclear Power Reactors” (EPID L-2018-LLA-0034), September 17, 2019 (ADAMS Accession No. ML19192A012)

46. RG 1.1, Revision 0, Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps (ADAMS Accession No. ML003739925)

47. RG 1.183, Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors, July 2000 (ADAMS Accession No. ML003716792)

PROPOSED TECHNICAL SPECIFICATION CHANGES (MARK-UP)

SHEARON HARRIS NUCLEAR POWER PLANT, UNIT 1

DOCKET NO. 50-400

RENEWED LICENSE NO. NPF-63

(8 pages including cover)

CONTAINMENT INTEGRITY

## LIMITING CONDITION FOR OPERATION

3.6.1.1 Primary CONTAINMENT INTEGRITY shall be maintained.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

Without primary CONTAINMENT INTEGRITY, restore CONTAINMENT INTEGRITY within 1 hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

## SURVEILLANCE REQUIREMENTS

4.6.1.1 Primary CONTAINMENT INTEGRITY shall be demonstrated:

a. At the frequency specified in the Surveillance Frequency Control Program by verifying that all penetrations*# not capable of being closed by OPERABLE containment automatic isolation valves and required to be closed during accident conditions are closed by valves, blind flanges, or deactivated automatic valves secured in their closed positions, except as provided in Table 3.6-1 of Specification 3.6.3;

b. By verifying that each containment air lock is in compliance with the requirements of Specification 3.6.1.3; and

c. ~~After each closing of each penetration subject to Type B testing, except the containment air locks, if opened following a Type A or B test, by leak rate testing the seal with gas at a pressure not less than $P_a$, and verifying that when the measured leakage rate for these seals is added to the leakage rates determined pursuant to Specification 4.6.1.2a. for all other Type B and C penetrations, the combined leakage rate is less than 0.60 $L_a$.~~

Replace with:
By performing required visual examinations and leakage rate testing, except for containment air lock testing, in accordance with the Containment Leakage Rate Testing Program.

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* Except valves, blind flanges, and deactivated automatic valves which are located inside the containment and are locked, sealed or otherwise secured in the closed position. These penetrations shall be verified closed during each COLD SHUTDOWN except that such verification need not be performed more often than once per 92 days.

\# Valves CP-B3, CP-B7, and CM-B5 may be verified at the frequency specified in the Surveillance Frequency Control Program by manual remote keylock switch position.

CONTAINMENT LEAKAGE

Replace with:
within the limits specified in the Containment Leakage Rate Testing Program.

LIMITING CONDITION FOR OPERATION

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3.6.1.2 Containment leakage rates shall be ~~limited to:~~

~~a.~~ ~~An overall integrated leakage rate within limits specified in the Containment Leakage Rate Testing Program.~~

~~b.~~ ~~A combined leakage rate of less than or equal to 0.60 $L_a$ for all penetrations and valves subject to Type B and C tests, when pressurized to $P_a$.~~

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

~~With either the measured overall integrated containment leakage rate exceeding 0.75 $L_a$, or the measured combined leakage rate for all penetrations and valves subject to Types B and C tests exceeding 0.60 $L_a$, restore the overall integrated leakage rate to less than 0.75 $L_a$, and the combined leakage rate for all penetrations subject to Type B and C tests to less than 0.60 $L_a$~~ prior to increasing the Reactor Coolant System temperature above 200°F.

Replace with:
<Insert>

SURVEILLANCE REQUIREMENTS

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4.6.1.2 The ~~Type A~~ containment leakage rate tests shall be performed in accordance with the Containment Leakage Rate Testing Program described in Technical Specification 6.8.4.k. ~~The Type B and Type C containment leakage rate tests shall be demonstrated at the test schedule and shall be determined in conformance with the criteria specified in 10 CFR 50 Appendix J, Option A.~~

<Insert>
With the containment leakage rate not within the limits specified in the Containment Leakage Rate Testing Program, restore the leakage rate to within the limits specified in the Containment Leakage Rate Program

SURVEILLANCE REQUIREMENTS (Continued)

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~~a.~~ ~~Type B and C tests shall be conducted with gas at a pressure not less than $P_a$, at intervals no greater than 24 months except for tests involving:~~

~~1.~~ ~~Air locks,~~

~~2.~~ ~~Containment purge makeup and exhaust isolation valves with resilient material seals;~~

~~b.~~ ~~Air locks shall be tested and demonstrated OPERABLE by the requirements of Specification 4.6.1.3;~~

~~c.~~ ~~Purge makeup and exhaust isolation valves with resilient material seals shall be tested and demonstrated OPERABLE by the requirements of Specification 4.6.1.7.2;~~

~~d.~~ ~~The provisions of Specification 4.0.2 are not applicable.~~

ADD:
the

SURVEILLANCE REQUIREMENTS

4.6.1.3 Each containment air lock shall be demonstrated OPERABLE by:

a. Performing required air lock leakage rate testing in accordance with ~~10 CFR 50, Appendix J~~, as modified by approved exemptions###. ~~The acceptance criteria for air lock testing are:~~

Replace with:
<Insert>

~~1. Overall air lock leakage rate is ≤ .05 $L_a$ when tested at ≥ $P_a$.~~

~~2. For each door, leakage rate is ≤ .01 $L_a$ when tested at ≥ $P_a$.~~

b. At the frequency specified in the Surveillance Frequency Control Program by verifying that only one door in the air lock can be opened at a time**.

<Insert>

the Containment Leakage Rate Testing Program

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### ~~1.~~ An inoperable air lock door does not invalidate the previous successful performance of the overall airlock leakage test.

~~2. Results shall be evaluated against Specification 3.6.1.2.a in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions.~~

** Only required to be performed upon entry or exit through the containment air lock. (If Surveillance Requirement 4.6.1.3.b has not been performed in the interval specified by the Surveillance Frequency Control Program, then perform Surveillance Requirement 4.6.1.3.b during the next containment entry through the associated air lock.)

CONTAINMENT VESSEL STRUCTURAL INTEGRITY

LIMITING CONDITION FOR OPERATION

---

3.6.1.6 The structural integrity of the containment vessel shall be maintained at a level consistent with the acceptance criteria in Specification 4.6.1.6.1.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

With the structural integrity of the containment vessel not conforming to the above requirements, restore the structural integrity to within the limits within 24 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

Replace with:
4.6.1.1.c

SURVEILLANCE REQUIREMENTS

---

4.6.1.6.1 Containment Vessel Surfaces. The structural integrity of the exposed accessible interior and exterior surfaces of the containment vessel, including the liner plate, shall be determined, during the shutdown for each Type A containment leakage rate test (reference Specification ~~4.6.1.2~~), by a visual inspection of these surfaces. This inspection shall be performed prior to the Type A containment leakage rate test to verify no apparent changes in appearance or other abnormal degradation. Additional inspections shall be conducted in accordance with Subsections IWE and IWL of the ASME Boiler and Pressure Vessel Code, Section XI.

4.6.1.6.2 Reports. Any abnormal degradation of the containment vessel structure detected during the above required inspections shall be reported to the Commission in a Special Report pursuant to Specification 6.9.2 within 15 days. This report shall include a description of the condition of the concrete, the inspection procedure, the tolerances on cracking, and the corrective actions taken.

PROCEDURES AND PROGRAMS (Continued)

k. Containment Leakage Rate Testing Program

A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54 (o) and 10 CFR 50 Appendix J, Option B, as modified by approved exemptions. This program shall be in ~~conformance with the NRC Regulatory Guide 1.163, "Performance Based Containment Leak Test Program," dated September 1995,~~ with the following exception~~s~~ noted:

Replace with: Insert 1

~~1) The above Containment Leakage Rate Testing Program is only applicable to Type A testing. Type B and C testing shall continue to be conducted in accordance with the original commitment to 10 CFR 50 Appendix J, Option A.~~

~~2) The first Type A test performed after the May 23, 1997 Type A test shall be performed no later than May 23, 2012.~~

~~3)~~ Visual examination of the containment system shall be in accordance with Specification 4.6.1.6.1.

The calculated peak containment internal pressure related to the design basis loss-of-coolant accident is 41.8 psig. The calculated peak containment internal pressure related to the design basis main steam line break is 41.3 psig. $P_a$ will be assumed to be 41.8 psig for the purpose of containment testing in accordance with this Technical Specification.

The maximum allowable containment leakage rate, $L_a$ at $P_a$, shall be 0.1 % of containment air weight per day.

ADD: Insert 2

The containment ~~overall~~ leakage rate acceptance criterion is $\leq 1.0$ $L_a$. During the first unit 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 Type C tests, and $\leq 0.75$ $L_a$ for Type A tests.

Replace with: Insert 3

~~The provisions of Surveillance Requirement 4.0.2 do not apply to the test frequencies specified in the Containment Leakage Rate Testing Program. However, test frequencies specified in this Program may be extended consistent with the guidance provided in Nuclear Energy Institute (NEI) 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR 50 Appendix J," as endorsed by Regulatory Guide 1.163. Specifically, NEI 94-01 has this provision for test frequency extension:~~

~~1) Consistent with standard scheduling practices for Technical Specifications Required Surveillances, intervals for recommended Type A testing may be extended by up to 15 months. This option should be used only in cases where refueling schedules have been changed to accommodate other factors.~~

The provisions of Surveillance Requirement 4.0.3 are applicable to the Containment Leakage Rate Testing Program.

ADD: Insert 4

INSERT 1

accordance with the guidelines contained in 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, dated July 2012, and the conditions and limitations specified in NEI 94-01, Revision 2-A, dated October 2008,

INSERT 2

Leakage rate acceptance criteria:

1)

INSERT 3

2) Air lock testing acceptance criteria are:

a) Overall air lock leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$.

b) For each door, leakage rate is $\leq 0.01\ L_a$ when pressurized to $\geq P_a$.

INSERT 4

Nothing in these Technical Specifications shall be construed to modify the testing frequencies required by 10 CFR 50, Appendix J.

U.S. Nuclear Regulatory Commission
RA-19-0067
Enclosure Attachment 2

PROPOSED TECHNICAL SPECIFICATION BASES CHANGES (MARK-UP)

SHEARON HARRIS NUCLEAR POWER PLANT, UNIT 1

DOCKET NO. 50-400

RENEWED LICENSE NO. NPF-63

(2 pages including cover)

## 3/4.6.1 PRIMARY CONTAINMENT

### 3/4.6.1.1 CONTAINMENT INTEGRITY

Primary CONTAINMENT INTEGRITY ensures that the release of radioactive materials from the containment atmosphere will be restricted to those leakage paths and associated leak rates assumed in the safety analyses. This restriction, in conjunction with the leakage rate limitation, will limit the SITE BOUNDARY radiation doses to within the dose guideline values of 10 CFR Part 100 during accident conditions.

### 3/4.6.1.2 CONTAINMENT LEAKAGE

The limitations on containment leakage rates ensure that the total containment leakage volume will not exceed the value assumed in the safety analyses at the peak accident pressure, $P_a$. As an added conservatism, the measured overall integrated leakage rate is further limited to less than or equal to 0.75 $L_a$, during performance of the periodic test, to account for possible degradation of the containment leakage barriers between leakage tests.

The surveillance testing for measuring leakage rates is consistent with the requirements of ~~Appendix J of 10 CFR Part 50, Option A for Type B and C tests, and~~ the Containment Leakage Rate Testing Program for Type A tests.

ADD:
, B, and C

### 3/4.6.1.3 CONTAINMENT AIR LOCKS

The limitations on closure and leak rate for the containment air locks are required to meet the restrictions on CONTAINMENT INTEGRITY and containment leak rate. Surveillance testing of the air lock seals provides assurance that the overall air lock leakage will not become excessive due to seal damage during the intervals between air lock leakage tests.

Action statement "a" has been modified by a note. The note allows use of the air lock for entry and exit for seven days under administrative controls if both air locks have an inoperable door. This seven day restriction begins when a door in the second air lock is discovered to be inoperable. Containment entry may be required to perform Technical Specification surveillances and actions, as well as other activities on equipment inside containment that are required by Technical Specifications (TS) or other activities that support TS required equipment. In addition, containment entry may be required to perform repairs on vital plant equipment, which if not repaired, could lead to a plant transient or a reactor trip. This note is not intended to preclude performing other activities (i.e., non-TS required activities or repairs on non-vital plant equipment) if the containment is entered, using the inoperable air lock, to perform an allowed activity listed above. This allowance is acceptable due to the low probability of an event that could pressurize containment during the short time that an OPERABLE door is expected to be open.

U.S. Nuclear Regulatory Commission
RA-19-0067
Enclosure Attachment 3

SHEARON HARRIS NUCLEAR POWER PLANT: EVALUATION OF RISK SIGNIFICANCE OF PERMANENT ILRT EXTENSION

SHEARON HARRIS NUCLEAR POWER PLANT, UNIT 1

DOCKET NO. 50-400

RENEWED LICENSE NO. NPF-63

(56 pages including cover)

JENSEN HUGHES

Advancing the Science of Safety

# Shearon Harris Nuclear Power Plant:
## Evaluation of Risk Significance of Permanent ILRT Extension

## 54012-CALC-01

## HNP-F/PSA-0127

**Prepared for:**

**Duke Energy Nuclear**

**Project Number: 1RCA54012**
**Project Title: Permanent ILRT Extension**

**(~~Vendor Revision 2~~) Duke Energy Revision 0**

| | Name and Date |
|---|---|
| Preparer: Kelly Wright | Digitally signed by Kelly Wright Date: 2019.09.13 16:58:53-04'00' |
| Reviewer: Justin Sattler | Digitally signed by Justin Sattler Date: 2019.09.13 16:10:14-05'00' |
| Review Method | Design Review ☒ Alternate Calculation ☐ |
| Approved by: Matthew Johnson | Digitally signed by Matt Johnson Date: 2019.09.16 13:11:12-05'00' |

# VENDOR REVISION RECORD SUMMARY

| Revision | Revision Summary |
|---|---|
| 0 | Initial Issue |
| 1 | Revised external events analysis to remove high winds impact due to hazard being screened as negligible contributor. Sections 3.0, 5.2.7, 5.2.7.1 have been revised and Section A.4 has been removed. |
| 2 | Incorporated revised fire PRA CDF and LERF totals provided by RNP-F/PSA-0126 Rev 1. Section 3.0 Reference 18 and Section 4.0 revised to clarify which fire PRA model was used in this assessment. Section 5.1.2 revised with new fire PRA CDF and LERF. Section 5.2.6 revised to include discussion of and new fire PRA model reference and revised associated risk metrics based on the revised fire PRA CDF and LERF. Section 7.0 revised to present revised risk metrics for external events (second bullet). |

## TABLE OF CONTENTS

# 1.0 PURPOSE

The purpose of this analysis is to provide a risk assessment of permanently extending the currently allowed containment Type A Integrated Leak Rate Test (ILRT) from ten years to fifteen years. The extension would allow for substantial cost savings as the ILRT could be deferred for additional scheduled refueling outages for the Shearon Harris Nuclear Power Plant (HNP). The risk assessment follows the guidelines from NEI 94-01, Revision 3-A [Reference 1], 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, risk insights in support of a request for a plant's licensing basis as outlined in Regulatory Guide (RG) 1.174 [Reference 4], the methodology used for Calvert Cliffs to estimate the likelihood and risk implications of corrosion-induced leakage of steel liners going undetected during the extended test interval [Reference 5], and the methodology used in EPRI 1018243, Revision 2-A of EPRI 1009325 [Reference 24].

# 2.0 SCOPE

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

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

The NRC report on performance-based leak testing, NUREG-1493, analyzed the effects of containment leakage on the health and safety of the public and the benefits realized from the containment leak rate testing. In that analysis, it was determined that for a representative 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 HNP.

NEI 94-01 Revision 3-A supports using EPRI Report No. 1009325 Revision 2-A (EPRI 1018243), "Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals," for performing risk impact assessments in support of ILRT extensions [Reference 24]. The Guidance provided in Appendix H of EPRI 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.

It should be noted that containment leak-tight integrity is also verified through periodic in-service inspections conducted in accordance with the requirements of the American Society of

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

The acceptance guidelines in RG 1.174 are used to assess the acceptability of this permanent extension of the Type A test interval beyond that established during the Option B rulemaking of Appendix J. RG 1.174 defines very small changes in the risk-acceptance guidelines as increases in Core Damage Frequency (CDF) less than $10^{-6}$ per reactor year and increases in Large Early Release Frequency (LERF) less than $10^{-7}$ per reactor year. Since 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), which helps ensure the defense-in-depth philosophy is maintained, is also calculated.

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

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

# 3.0 REFERENCES

The following references were used in this calculation:


1. *Revision 3-A to Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J*, NEI 94-01, July 2012.
2. *Risk Impact Assessment of Revised Containment Leak Rate Testing Intervals*, EPRI, Palo Alto, CA EPRI TR-104285, August 1994.
3. *Interim Guidance for Performing Risk Impact Assessments in Support of One-Time Extensions for Containment Integrated Leakage Rate Test Surveillance Intervals*, Revision 4, developed for NEI by EPRI and Data Systems and Solutions, November 2001.
4. An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis, Regulatory Guide 1.174, Revision 3, January 2018.
5. *Response to Request for Additional Information Concerning the License Amendment Request for a One-Time Integrated Leakage Rate Test Extension*, Letter from Mr. C. H. Cruse (Calvert Cliffs Nuclear Power Plant) to NRC Document Control Desk, Docket No. 50-317, March 27, 2002.
6. Performance-Based Containment Leak-Test Program, NUREG-1493, September 1995.
7. *Evaluation of Severe Accident Risks: Surry Unit 1*, Main Report NUREG/CR-4551, SAND86-1309, Volume 3, Revision 1, Part 1, October 1990.
8. Letter from R. J. Barrett (Entergy) to U. S. Nuclear Regulatory Commission, IPN-01-007, January 18, 2001.
9. United States Nuclear Regulatory Commission, Indian Point Nuclear Generating Unit No. 3 – Issuance of Amendment Re: Frequency of Performance-Based Leakage Rate Testing (TAC No. MB0178), April 17, 2001.
10. *Impact of Containment Building Leakage on LWR Accident Risk*, Oak Ridge National Laboratory, NUREG/CR-3539, ORNL/TM-8964, April 1984.
11. *Reliability Analysis of Containment Isolation Systems*, Pacific Northwest Laboratory, NUREG/CR-4220, PNL-5432, June 1985.
12. Technical Findings and Regulatory Analysis for Generic Safety Issue II.E.4.3 'Containment Integrity Check', NUREG-1273, April 1988.
13. *Review of Light Water Reactor Regulatory Requirements*, Pacific Northwest Laboratory, NUREG/CR-4330, PNL-5809, Volume 2, June 1986.
14. Shutdown Risk Impact Assessment for Extended Containment Leakage Testing Intervals Utilizing ORAM™, EPRI, Palo Alto, CA, TR-105189, Final Report, May 1995.
15. *Severe Accident Risks: An Assessment for Five U. S. Nuclear Power Plants*, NUREG-1150, December 1990.
16. United States Nuclear Regulatory Commission, Reactor Safety Study, WASH-1400, October 1975.
17. Calculation HNP-F/PSA-0086, Revision 3, Shearon Harris Nuclear Plant, "PRA Model Sequence Quantification."

18. Calculation HNP-F/PSA-0126, Revision 1, Shearon Harris Nuclear Plant, “Harris FPRA - FPRA Update to Incorporate HNP2019 Internal Events model for ESCW LAR RAIs”
19. ML14148A235, 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), July 3, 2014.
20. Anthony R. Pietrangelo, One-time extensions of containment integrated leak rate test interval – additional information, NEI letter to Administrative Points of Contact, November 30, 2001.
21. Letter from J. A. Hutton (Exelon, Peach Bottom) to U. S. Nuclear Regulatory Commission, Docket No. 50-278, License No. DPR-56, LAR-01-00430, dated May 30, 2001.
22. *Risk Assessment for Joseph M. Farley Nuclear Plant Regarding ILRT (Type A) Extension Request*, prepared for Southern Nuclear Operating Co. by ERIN Engineering and Research, P0293010002-1929-030602, March 2002.
23. Letter from D. E. Young (Florida Power, Crystal River) to U. S. Nuclear Regulatory Commission, 3F0401-11, dated April 25, 2001.
24. *Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals*, Revision 2-A of 1009325, EPRI, Palo Alto, CA, 1018243, October 2008.
25. Risk Assessment for Vogtle Electric Generating Plant Regarding the ILRT (Type A) Extension Request, prepared for Southern Nuclear Operating Co. by ERIN Engineering and Research, February 2003.
26. Perspectives Gained from the IPEEE Program, USNRC, NUREG-1742, April 2002.
27. License Amendment Regarding Risk-Informed Justifications for the Relocation of Specific Surveillance Frequency Requirements to a Licensee-Controlled Program, November 29, 2016 ADAMS Accession No. ML16200A285
28. Generic Issue 199 (GI-199), ML100270582, September 2010, “Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern United States on Existing Plants: Safety/Risk Assessment.”
29. Technical Letter Report ML112070867, Containment Liner Corrosion Operating Experience Summary, Revision 1, August 2011.
30. “The Nuclear Energy Institute - Seismic Risk Evaluations for Plants in the Central and Eastern United States,” ML14083A596, March 2014.
31. Calculation HNP-F/PSA-0095, Revision 1, Shearon Harris Nuclear Plant, “HNP Internal Flooding Quantification.”
32. Shearon Harris Nuclear Power Plant, “Updated Final Safety Analysis Report.”
33. ML17257A043, “Response to March 12, 2012, Request for Information Enclosure 2, Recommendation 2.1, Flooding, Required Response 3, Flooding Focused Evaluation Summary Submittal,” September 13, 2017.
34. Individual Plant Examination of External Events for the Shearon Harris Nuclear Power Plant Unit No. 1, June 1995.
35. EPRI TR-1019259, “Fire Probabilistic Risk Assessment Methods Enhancements: Supplement 1 to NUREG/CR-6850 and EPRI 1011989,” December 2009.

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

37. ASME/ANS RA-Sa–2009, Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications,” 2009.

38. NRC Letter to Mr. Greg Krueger (NEI), “U.S. Nuclear Regulatory Commission Acceptance on Nuclear Energy Institute Appendix X to Guidance 05-04, 7-12, and 12-13, Close Out of Facts and Observations (F&Os),” May 3, 2017, (ML17079A427).

39. NUREG-2180, “Determining the Effectiveness, Limitations, and Operator Response for Very Early Warning Fire Detection Systems in Nuclear Facilities (DELORES-VEWFIRE),” December 2016.

40. Report 025114-RPT-01, “Shearon Harris Nuclear Power Plant Fire PRA Focused-Scope Peer Review,” Revision 0, June 2019.

41. Report 25114-RPT-02, “Shearon Harris Nuclear Power Plant PRA Fact and Observation Independent Assessment,” Revision 0, June 2019.

42. ML16217A449, “Shearon Harris Nuclear Power Plant, Unit 1 – Safety Evaluation Regarding Implementation of Mitigating Strategies and Reliable Spent Fuel Pool Instrumentation Related to Orders EA-12-049 and EA-12-051 (CAC Nos. MF0874 and MF0792),” August 30, 2016.

43. License Amendment Regarding Adoption of National Fire Protection Association Standard 805, June 28, 2010 ADAMS Accession No. ML10750602

44. ML18033B768, Sharon Harris Nuclear Power Plant, Unit 1, Application to Adopt 10 CFR 50.69, “Risk-Informed Categorization and Treatment of Structures, Systems, and Components (SSCs) for Nuclear Power Reactor,” Docket No. 50-400, License No. NPF-63, February 1, 2018.

45. ML15236A256, Sharon Harris Nuclear Power Plant, Unit 1, “Application for Technical Specification Change Regarding Risk-Informed Risk-Informed Justification for the Relocation of Specific Surveillance Frequency Requirements to a Licensee-Controlled Program,” Docket No. 50-400, License No. NPF-63, August 18, 2015.

# 4.0 ASSUMPTIONS AND LIMITATIONS

The following assumptions were used in the calculation:

- The acceptability (i.e., technical adequacy) of the HNP PRA [Reference 17] is either consistent with the requirements of Regulatory Guide 1.200, or where gaps exist, the gaps have been addressed, as detailed in Attachment 1.
- The HNP Level 1 and Level 2 internal events PRA models provide representative results.
- It is appropriate to use the HNP internal events PRA model to effectively describe the risk change attributable to the ILRT extension. An analysis is performed in Section 5.2.7 to show the effect of including external event models for the ILRT extension. The Seismic risk from GI-199 [Reference 28] and Fire PRA model Revision 5 with changes incorporated for the Essential Services Chilled Water System Allowed Out of Service Time LAR [Reference 18] are used for this analysis.
- Accident classes describing radionuclide release end states are defined consistent with EPRI methodology [Reference 24].
- The representative containment leakage for Class 1 sequences is $1L_a$. Class 3 accounts for increased leakage due to Type A inspection failures.
- The representative containment leakage for Class 3a sequences is $10L_a$ based on the previously approved methodology performed for Indian Point Unit 3 [Reference 8, Reference 9].
- The representative containment leakage for Class 3b sequences is $100L_a$ based on the guidance provided in EPRI Report No. 1009325, Revision 2-A (EPRI 1018243) [Reference 24].
- The Class 3b can be very conservatively categorized as LERF based on the previously approved methodology [Reference 8, Reference 9].
- The impact on population doses from containment bypass scenarios is not altered by the proposed ILRT extension, but is accounted for in the EPRI methodology as a separate entry for comparison purposes. Since the containment bypass contribution to population dose is fixed, no changes in the conclusions from this analysis will result from this separate categorization.
- The reduction in ILRT frequency does not impact the reliability of containment isolation valves to close in response to a containment isolation signal [Reference 24].
- While precise numbers are maintained throughout the calculations, some values have been rounded when presented in this report. Therefore, summing individual values within tables may yield a different result than the sum result shown in the table.

# 5.0 METHODOLOGY AND ANALYSIS

## 5.1 Inputs

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

### 5.1.1 General Resources Available

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

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

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

<u>NUREG/CR-3539 [Reference 10]</u>

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

<u>NUREG/CR-4220 [Reference 11]</u>

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

NUREG-1273 [Reference 12]

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

NUREG/CR-4330 [Reference 13]

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

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

EPRI TR-105189 [Reference 14]

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

NUREG-1493 [Reference 6]

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

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

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

EPRI TR-104285 [Reference 2]

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

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

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

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

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

"…the proposed CLRT (Containment Leak Rate Tests) frequency changes would have a minimal safety impact. The change in risk determined by the analyses is small in both absolute and relative terms. For example, for the PWR analyzed, the change is about 0.02 person-rem per year…"

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

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

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

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

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

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

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

This report provides a generally applicable assessment of the risk involved in extension of ILRT test intervals to permanent 15-year intervals. Appendix H of this document provides guidance for performing plant-specific supplemental risk impact assessments and builds on the previous EPRI risk 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 HNP assessment to determine the estimated increase in risk associated with the ILRT extension. This document includes the bases for the values assigned in determining the probability of leakage for the EPRI Class 3a and 3b scenarios in this analysis, as described in Section 5.2.

### 5.1.2 Plant Specific Inputs

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

- CDF and LERF Model results [Reference 17, Reference 18, Reference 31]
- Dose within a 50-mile radius [Reference 32]

HNP Model

The Internal Events PRA Model that is used for HNP is characteristic of the as-built plant. The current Level 1, LERF, and Level 2 model (MOR18) is a linked fault tree model [Reference 17]. The CDF is 2.89E-6/year; the LERF is 1.07E-6/year [Reference 17]. The CDF from Internal Floods is 5.76E-06/year and the LERF from Internal Floods is 4.77E-07/year [Reference 31]. Therefore, the total CDF for Internal Events is 8.65E-06/year and the total LERF is 1.55E-06/year. Table 5-1 and Table 5-2 provide a summary of the Internal Events CDF and LERF results for the HNP PRA Model.

The total Fire CDF is 4.48E-05/year; the total Fire LERF is 3.21E-06/year [Reference 18]. The seismic risk is taken from GI-199 [Reference 28]. Refer to Section 5.2.7 for further details on external events as they pertain to this analysis.

**Table 5-1 – Internal Events CDF**

| Internal Events | Frequency (per year) |
|---|---|
| Internal Floods | 5.76E-06 |
| LOCAs | 9.17E-07 |
| Transients | 9.12E-07 |
| SGTR | 8.46E-07 |
| ISLOCA | 1.54E-07 |
| Loss of Offsite Power | 3.48E-08 |
| RPV Rupture | 2.64E-08 |
| **Total Internal Events CDF** | 8.65E-06 |

**Table 5-2 – Internal Events LERF**

| Internal Events | Frequency (per year) |
|---|---|
| SGTR | 8.49E-07 |
| Internal Floods | 4.77E-07 |
| ISLOCA | 1.55E-07 |
| Transients | 4.53E-08 |
| LOCAs | 1.82E-08 |
| LOOP | 2.82E-09 |
| RPV Rupture | 2.46E-10 |
| **Total Internal Events LERF** | 1.55E-06 |

Release Category Definitions

Table 5-3 defines the accident classes used in the ILRT extension evaluation, which is consistent with the EPRI methodology [Reference 24]. These containment failure classifications are used in this analysis to determine the risk impact of extending the Containment Type A test interval, as described in Section 5.2 of this report.

**Table 5-3 – EPRI Containment Failure Classification [Reference 24]**

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

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

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

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

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

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

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

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

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

## 5.2 Analysis

The application of the approach based on the guidance contained in EPRI 1009325 [Reference 24] and previous risk assessment submittals on this subject [References 5, 8, 21, 22, and 23] have led to the following results. The results are displayed according to the eight accident classes defined in the EPRI report, as described in Table 5-4.

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

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

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

**Table 5-4 – EPRI Accident Class Definitions**

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

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

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

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

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

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

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

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

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

For the assessment of ILRT impacts on the risk profile, the potential for pre-existing leaks is included in the model (these events are represented by the Class 3 sequences in EPRI 1009325 [Reference 24]). The question on containment integrity was modified to include the probability of a liner breach or bellows failure (due to excessive leakage) at the time of core damage. Two failure modes were considered for the Class 3 sequences. These are Class 3a (small breach) and Class 3b (large breach).

The frequencies for the severe accident classes defined in Table 5-4 were developed for HNP by first determining the frequencies for Classes 1, 2, 6, 7, and 8. Table 5-5 presents the frequency and EPRI category for each sequence and the totals of each EPRI classification. Table 5-6 provides a summary of the accident sequence frequencies that can lead to radionuclide release to the public and have been derived consistent with the NEI Interim Guidance [Reference 3] and the definitions of accident classes and guidance provided in EPRI Report No. 1009325, Revision 2-A [Reference 24]. Adjustments were made to the Class 3b and hence Class 1 frequencies to account for the impact of undetected corrosion of the steel liner per the methodology described in Section 5.2.6. Note: calculations were performed with more digits than shown in this section. Therefore, minor differences may occur if the calculations in these sections are followed explicitly.

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

Data reported in EPRI 1009325, Revision 2-A [Reference 24] states that two events could have been detected only during the performance of an ILRT and thus impact risk due to change in ILRT frequency. There were a total of 217 successful ILRTs during this data collection period. Therefore, the probability of leakage is determined for Class 3a as shown in the following equation:

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

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

$$Freq_{class3a} = P_{class3a} * (CDF - LERF) = \frac{2}{217} * (8.65\text{E-}6 - 1.55\text{E-}6) = 6.55\text{E-}08$$

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

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

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

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

$$Freq_{class3b} = P_{class3b} * (CDF - LERF) = \frac{.5}{217} * (8.65\text{E-}6 - 1.55\text{E-}6) = 1.63\text{E-}08$$

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

Class 1 Sequences. This group consists of all core damage accident progression bins for which the containment remains intact (modeled as Technical Specification Leakage). The Intact frequency for internal events, 1.21E-06, is provided in Table 13 of Reference 17. The ratio of intact to total CDF for internal events is 41.87%; this same ratio was assumed for internal flooding leading to an intact frequency of 2.41E-06. Thus, the total EPRI Accident Class 1 frequency is the summation of the intact frequency for internal events and internal flooding, or 3.62E-06, as shown in Table 5-5. The EPRI Accident Class 1 frequency is then adjusted by subtracting the EPRI Class 3a and 3b frequency (to preserve total CDF), calculated below:

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

Class 2 Sequences. This group consists of core damage accident progression bins with large containment isolation failures. The large isolation failure frequency for internal events, 7.73E-09, is provided in Table 13 of Reference 17. The ratio of large isolation failure to total CDF for internal events is 0.27%; this same ratio was assumed for internal flooding leading to a large isolation failure frequency of 1.54E-08. Thus, the total EPRI Accident Class 2 frequency is the summation of the large isolation failure frequency for internal events and internal flooding, or 2.31E-08, as shown in Table 5-5.

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

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

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

Class 7 Sequences. This group consists of all core damage accident progression bins in which containment failure is induced by severe accident phenomena (e.g., overpressure). This frequency is calculated by subtracting the Class 1, 2, and 8 frequencies from the total CDF. For this analysis, the frequency is determined from the EPRI Accident Class 7 frequency listed in Table 5-5.

Class 8 Sequences. This group consists of all core damage accident progression bins in which containment is bypassed via ISLOCA or SGTR. Table 13 of Reference 17 provides both small and large Bypass frequencies, 1.20E-07 and 8.03E-07, respectively. For EPRI Accident Class 8, the small and large bypass frequencies are combined to obtain a frequency of 9.23E-07. The ratio of bypass failure to total CDF for internal events is 31.94%; this same ratio was assumed for internal flooding leading to a bypass failure frequency of 1.84E-06. Thus, the total EPRI Accident Class 8 frequency is the summation of the bypass failure frequency for internal events and internal flooding, or 2.76E-06, as shown in Table 5-5.

**Table 5-5 – Accident Class Frequencies**

| EPRI Category | Frequency (/yr) |
|---|---|
| Class 1 | 3.62E-06 |
| Class 2 | 2.31E-08 |
| Class 7 | 2.24E-06 |
| Class 8 | 2.76E-06 |
| Total (CDF) | 8.65E-06 |

1. ε represents a probabilistically insignificant value.

**Table 5-6 – Baseline Risk Profile**

| Class | Description | Frequency (/yr) |
|---|---|---|
| 1 | No containment failure | 3.54E-06[2] |
| 2 | Large containment isolation failures | 2.31E-08 |
| 3a | Small isolation failures (liner breach) | 6.55E-08 |
| 3b | Large isolation failures (liner breach) | 1.63E-08 |
| 4 | Small isolation failures - failure to seal (type B) | ε[1] |
| 5 | Small isolation failures - failure to seal (type C) | ε[1] |
| 6 | Containment isolation failures (dependent failure, personnel errors) | ε[1] |
| 7 | Severe accident phenomena induced failure (early and late) | 2.24E-06 |
| 8 | Containment bypass | 2.76E-06 |
| | Total | 8.65E-06 |

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

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

Plant-specific release analyses were performed to estimate the person-rem doses to the population within a 50-mile radius from the plant. The population dose for Classes 1, 2, 7, and 8 are calculated using the methodology of scaling Surry population doses to HNP [Reference 7]. The adjustment factor for reactor power level ($AF_{power}$) is defined as the ratio of the power level at HNP (PLH) [Reference 32] to that at Surry (PLS) [Reference 7]. This adjustment factor is calculated as follows:

$$AF_{power} = PLH \,/\, PLS = 2948 \,/\, 2441 = 1.208$$

The adjustment factor for technical specification (TS) allowed containment leakage is defined as the ratio of the containment leakage at Harris (LRH) to that at Surry (LRS). This adjustment factor is calculated as follows:

$$AF_{leakage} = LRH \,/\, LRS$$

Since the leakage rates are in terms of the containment volume, the ratio of containment volumes is needed to relate the leakage rates. The TS maximum allowed containment leakage at HNP ($TS_H$) is 0.1%/day [Reference 32]; the containment free volume at HNP ($VOL_H$) is 2,266,000 $ft^3$ [Reference 32]. The TS maximum allowed containment leakage at Surry ($TS_S$) is 0.1%/day [Reference 19]; the containment free volume at Surry ($VOL_S$) is 1,800,000 $ft^3$ [Reference 7]. Therefore,

$$LRH = TS_H * VOL_H$$

$$LRS = TS_S * VOL_S$$

$$AF_{leakage} = (0.1 * 2266000) \,/\, (0.1 * 1800000) = 1.259$$

The adjustment factor for population ($AF_{Population}$) is defined as the ratio of the population within 50-mile radius of HNP (POPH) [Reference 32] to that of Surry (POPS) [Reference 7]. The 2027 population surrounding HNP was conservatively estimated as 3,540,592 [Reference 32]. This adjustment factor is calculated as follows:

$AF_{Population} = POPH \,/\, POPS = 3540592 \,/\, 1231275 = 2.876$Consequences dependent on the INTACT TS Leakage (collapsed accident progression bins 6 and 7).

$AF_{INTACT} = AF_{power} * AF_{Leakage} * AF_{Population} = 1.208 * 1.259 * 2.876 = 4.372$

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

$AF = AF_{power} * AF_{Population} = 1.208 * 2.876 = 3.473$

The population dose data in NUREG/CR-4551 for Surry [Reference 7] is reported in ten distinct collapsed accident progression bins (CAPBs). For this ILRT extension application, CAPB6 and CAPB7 are categorized in EPRI Accident Class 1; CAPB2 is categorized in EPRI Accident Class 2; CAPB4 is categorized in EPRI Accident Class 7; and CAPB5 is categorized in EPRI Accident Class 8. Based on the above adjustment factors and the 50-mile population dose (person-rem) for each CAPB considered in the NUREG/CR-4551 Surry study, the HNP population doses (HPD) for Classes 1, 2, 7 and 8 are calculated as follows:

$HPD_{Class1} = AF_{INTACT} * PD_{CAPB6} + AF_{INTACT} * PD_{CAPB7} = 4.372 * 4.23E{+}2 + 4.372 * 5.76E{+}2 = 4.37E{+}3$

$HPD_{Class2} = AF * PD_{CAPB2} = 3.473 * 6.46E{+}5 = 2.24E{+}6$

$HPD_{Class7} = AF * PD_{CAPB4} = 3.473 * 4.95E{+}5 = 1.72E{+}6$

$HPD_{Class8} = AF * PD_{CAPB5} = 3.473 * 8.12E{+}5 = 2.82E{+}6$

Table 5-7 provides a correlation of HNP population dose to EPRI Accident Class. Table 5-8 presents dose exposures calculated from the methodology described in Reference 24. Table 5-9 presents the baseline risk profile for HNP.

The population dose for EPRI Accident Classes 3a and 3b were calculated based on the guidance provided in EPRI Report No. 1009325, Revision 2-A [Reference 24] as follows:

$EPRI\ Class\ 3a\ Population\ Dose = 10 * 4.37E{+}3 = 4.37E{+}4$

$EPRI\ Class\ 3b\ Population\ Dose = 100 * 4.37E{+}3 = 4.37E{+}5$

**Table 5-7 – Mapping of Population Dose to EPRI Accident Class**

| EPRI Category | Frequency (/yr) | Dose (person-rem) |
|---|---|---|
| Class 1 | 3.62E-06 | 4.37E+03 |
| Class 2 | 2.31E-08 | 2.24E+06 |
| Class 7 | 2.24E-06 | 1.72E+06 |
| Class 8 | 2.76E-06 | 2.82E+06 |

**Table 5-8 – Baseline Population Doses**

| Class | Description | Population Dose (person-rem) |
|---|---|---|
| 1 | No containment failure | 4.37E+03 |
| 2 | Large containment isolation failures | 2.24E+06 |
| 3a | Small isolation failures (liner breach) | 4.37E+04[1] |
| 3b | Large isolation failures (liner breach) | 4.37E+05[2] |
| 4 | Small isolation failures - failure to seal (type B) | N/A |
| 5 | Small isolation failures - failure to seal (type C) | N/A |
| 6 | Containment isolation failures (dependent failure, personnel errors) | N/A |

**Table 5-8 – Baseline Population Doses**

| Class | Description | Population Dose (person-rem) |
|---|---|---|
| 7 | Severe accident phenomena induced failure (early and late) | 1.72E+06 |
| 8 | Containment bypass | 2.82E+06 |

1. 10*$L_a$
2. 100*$L_a$

**Table 5-9 – Baseline Risk Profile for ILRT**

| Class | Description | Frequency (/yr) | Contribution (%) | Population Dose (person-rem) | Population Dose Rate (person-rem/yr) |
|---|---|---|---|---|---|
| 1 | No containment failure[2] | 3.54E-06 | 40.92% | 4.37E+03 | 1.55E-02 |
| 2 | Large containment isolation failures | 2.31E-08 | 0.27% | 2.24E+06 | 5.19E-02 |
| 3a | Small isolation failures (liner breach) | 6.55E-08 | 0.76% | 4.37E+04 | 2.86E-03 |
| 3b | Large isolation failures (liner breach) | 1.63E-08 | 0.19% | 4.37E+05 | 7.12E-03 |
| 4 | Small isolation failures - failure to seal (type B) | ε[1] | ε[1] | ε[1] | ε[1] |
| 5 | Small isolation failures - failure to seal (type C) | ε[1] | ε[1] | ε[1] | ε[1] |
| 6 | Containment isolation failures (dependent failure, personnel errors) | ε[1] | ε[1] | ε[1] | ε[1] |
| 7 | Severe accident phenomena induced failure (early and late) | 2.24E-06 | 25.93% | 1.72E+06 | 3.86E+00 |
| 8 | Containment bypass | 2.76E-06 | 31.94% | 2.82E+06 | 7.79E+00 |
| | Total | **8.65E-06** | | | **1.17E+01** |

1. ε represents a probabilistically insignificant value or a Class that is unaffected by the Type A ILRT.
2. The Class 1 frequency is reduced by the frequency of Class 3a and Class 3b in order to preserve total CDF.

### 5.2.3 Step 3 – Evaluate Risk Impact of Extending Type A Test Interval from 10 to 15 Years

The next step is to evaluate the risk impact of extending the test interval from its current 10-year interval to a 15-year interval. To do this, an evaluation must first be made of the risk associated with the 10-year interval, since the base case applies to 3-year interval (i.e., a simplified representation of a 3-to-10 interval).

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 Class 3b sequences is impacted. The risk contribution is changed based on the NEI guidance as described in Section 5.1.3 by a factor of 10/3 compared to the base case values. The Class 3a and 3b frequencies are calculated as follows:

$$Freq_{Class3a10yr} = \frac{10}{3} * \frac{2}{217} * (CDF - LERF) = \frac{10}{3} * \frac{2}{217} * 7.10\text{E-}6 = 2.18\text{E-}7$$

$$Freq_{Class3b10yr} = \frac{10}{3} * \frac{.5}{218} * (CDF - LERF) = \frac{10}{3} * \frac{.5}{218} * 7.10\text{E-}6 = 5.43\text{E-}8$$

The results of the calculation for a 10-year interval are presented in Table 5-10.

**Table 5-10 – Risk Profile for Once in 10 Year ILRT**

| Class | Description | Frequency (/yr) | Contribution (%) | Population Dose (person-rem) | Population Dose Rate (person-rem/yr) |
|---|---|---|---|---|---|
| 1 | No containment failure[2] | 3.35E-06 | 38.72% | 4.37E+03 | 1.46E-02 |
| 2 | Large containment isolation failures | 2.31E-08 | 0.27% | 2.24E+06 | 5.19E-02 |
| 3a | Small isolation failures (liner breach) | 2.18E-07 | 2.52% | 4.37E+04 | 9.53E-03 |
| 3b | Large isolation failures (liner breach) | 5.43E-08 | 0.63% | 4.37E+05 | 2.37E-02 |
| 4 | Small isolation failures - failure to seal (type B) | ε[1] | ε[1] | ε[1] | ε[1] |
| 5 | Small isolation failures - failure to seal (type C) | ε[1] | ε[1] | ε[1] | ε[1] |
| 6 | Containment isolation failures (dependent failure, personnel errors) | ε[1] | ε[1] | ε[1] | ε[1] |
| 7 | Severe accident phenomena induced failure (early and late) | 2.24E-06 | 25.93% | 1.72E+06 | 3.86E+00 |
| 8 | Containment bypass | 2.76E-06 | 31.94% | 2.82E+06 | 7.79E+00 |
| | Total | **8.65E-06** | | | **1.17E+01** |

1. ε represents a probabilistically insignificant value or a Class that is unaffected by the Type A ILRT.
2. The Class 1 frequency is reduced by the frequency of Class 3a and Class 3b in order to preserve total CDF.

Risk Impact Due to 15-Year Test Interval

The risk contribution for a 15-year interval is calculated in a manner similar to the 10-year interval. The difference is in the increase in probability of leakage in Classes 3a and 3b. For this case, the value used in the analysis is a factor of 5 compared to the 3-year interval value, as described in Section 5.1.3. The Class 3a and 3b frequencies are calculated as follows:

$$Freq_{Class3a15yr} = \frac{15}{3} * \frac{2}{217} * (CDF - LERF) = 5 * \frac{2}{217} * 7.10\text{E-}6 = 3.27\text{E-}7$$

$$Freq_{Class3b15yr} = \frac{15}{3} * \frac{.5}{218} * (CDF - LERF) = 5 * \frac{.5}{218} * 7.10\text{E-}6 = 8.15\text{E-}8$$

The results of the calculation for a 15-year interval are presented in Table 5-11.

**Table 5-11 – Risk Profile for Once in 15 Year ILRT**

| Class | Description | Frequency (/yr) | Contribution (%) | Population Dose (person-rem) | Population Dose Rate (person-rem/yr) |
|---|---|---|---|---|---|
| 1 | No containment failure[2] | 3.21E-06 | 37.14% | 4.37E+03 | 1.40E-02 |
| 2 | Large containment isolation failures | 2.31E-08 | 0.27% | 2.24E+06 | 5.19E-02 |
| 3a | Small isolation failures (liner breach) | 3.27E-07 | 3.78% | 4.37E+04 | 1.43E-02 |
| 3b | Large isolation failures (liner breach) | 8.15E-08 | 0.94% | 4.37E+05 | 3.56E-02 |
| 4 | Small isolation failures - failure to seal (type B) | ε[1] | ε[1] | ε[1] | ε[1] |
| 5 | Small isolation failures - failure to seal (type C) | ε[1] | ε[1] | ε[1] | ε[1] |
| 6 | Containment isolation failures (dependent failure, personnel errors) | ε[1] | ε[1] | ε[1] | ε[1] |
| 7 | Severe accident phenomena induced failure (early and late) | 2.24E-06 | 25.93% | 1.72E+06 | 3.86E+00 |
| 8 | Containment bypass | 2.76E-06 | 31.94% | 2.82E+06 | 7.79E+00 |
| | Total | **8.65E-06** | | | **1.18E+01** |

1. ε represents a probabilistically insignificant value or a Class that is unaffected by the Type A ILRT.
2. The Class 1 frequency is reduced by the frequency of Class 3a and Class 3b in order to preserve total CDF.

### 5.2.4 Step 4 – Determine the Change in Risk in Terms of LERF

The risk increase associated with extending the ILRT interval involves the potential that a core damage event that normally would result in only a small radioactive release from an intact containment could, in fact, result in a larger release due to the increase in probability of failure to detect a pre-existing leak. With strict adherence to the EPRI guidance, 100% of the Class 3b contribution would be considered LERF.

Regulatory Guide 1.174 [Reference 4] provides guidance for determining the risk impact of plant-specific changes to the licensing basis. RG 1.174 [Reference 4] defines very small changes in risk as resulting in increases of CDF less than $10^{-6}$/year and increases in LERF less than $10^{-7}$/year, and small changes in LERF as less than $10^{-6}$/year. Since containment overpressure is not required in support of ECCS performance to mitigate design basis accidents and no equipment in the shield building is credited in the CDF model at HNP, the ILRT extension does not impact CDF. Therefore, the relevant risk-impact metric is LERF.

For HNP, 100% of the frequency of Class 3b sequences can be used as a very conservative first-order estimate to approximate the potential increase in LERF from the ILRT interval extension (consistent with the EPRI guidance methodology). Based on a 10-year test interval from Table 5-10, the Class 3b frequency is 5.43E-8/year; based on a 15-year test interval from Table 5-11, the Class 3b frequency is 8.15E-8/year. Thus, the increase in the overall probability of LERF due to Class 3b sequences that is due to increasing the ILRT test interval from 3 to 15 years is 6.52E-8/year. Similarly, the increase due to increasing the interval from 10 to 15 years is 2.72E-8/year. As can be seen, even with the conservatisms included in the evaluation (per the EPRI methodology), the estimated change in LERF meets the criteria for a very small change when comparing the 15-year results to the current 10-year requirement and the original 3-year requirement. Table 5-12 summarizes these results.

**Table 5-12 – Impact on LERF due to Extended Type A Testing Intervals**

| ILRT Inspection Interval | 3 Years (baseline) | 10 Years | 15 Years |
|---|---|---|---|
| Class 3b (Type A LERF) | 1.63E-08 | 5.43E-08 | 8.15E-08 |
| ΔLERF (3 year baseline) | | 3.80E-08 | 6.52E-08 |
| ΔLERF (10 year baseline) | | | 2.72E-08 |

The increase in the overall probability of LERF due to Class 3b sequences is less than $10^{-7}$.

NEI 94-01 [Reference 1] states that a small population dose is defined as an increase of ≤ 1.0 person-rem per year, or ≤ 1% of the total population dose, whichever is less restrictive for the risk impact assessment of the extended ILRT intervals. As shown in Table 5-13, the results of this calculation meet the dose rate criteria.

**Table 5-13 – Impact on Dose Rate due to Extended Type A Testing Intervals**

| ILRT Inspection Interval | 10 Years | 15 Years |
|---|---|---|
| ΔDose Rate (3 year baseline) | 2.244E-02 | 3.847E-02 |
| ΔDose Rate (10 year baseline) | | 1.603E-02 |
| %ΔDose Rate (3 year baseline) | 0.191% | 0.328% |
| %ΔDose Rate (10 year baseline) | | 0.136% |

1. ΔDose Rate is the difference in the total dose rate between cases. For instance, 'ΔDose Rate (3 year baseline)' for the 1 in 15 case is the total dose rate of the 1 in 15 case minus the total dose rate of the 3 in 10 year case.
2. %ΔDose Rate is the ΔDose Rate divided by the total baseline dose rate. For instance, '%ΔDose Rate (3 year baseline)' for the 1 in 15 case is the 'ΔDose Rate (3 year baseline)' of the 1 in 15 year case divided by the total dose rate of the 3 in 10 year case.

### 5.2.5 Step 5 – Determine the Impact on the Conditional Containment Failure Probability

Another parameter that the NRC guidance in RG 1.174 [Reference 4] states can provide input into the decision-making process is the change in the conditional containment failure probability (CCFP). The CCFP is defined as the probability of containment failure given the occurrence of an accident. This probability can be expressed using the following equation:

$$CCFP = 1 - \frac{f(ncf)}{CDF}$$

where *f*(ncf) is the frequency of those sequences that do not result in containment failure; this frequency is determined by summing the Class 1 and Class 3a results.

Table 5-14 shows the steps and results of this calculation.

**Table 5-14 – Impact on CCFP due to Extended Type A Testing Intervals**

| ILRT Inspection Interval | 3 Years (baseline) | 10 Years | 15 Years |
|---|---|---|---|
| *f*(ncf) (/yr) | 3.61E-06 | 3.57E-06 | 3.54E-06 |
| *f*(ncf)/CDF | 0.417 | 0.412 | 0.409 |
| CCFP | 0.583 | 0.588 | 0.591 |
| ΔCCFP (3 year baseline) | | 0.439% | 0.753% |
| ΔCCFP (10 year baseline) | | | 0.314% |

As stated in Section 2.0, a change in the CCFP of up to 1.5% is assumed to be small. The increase in the CCFP from the 3 in 10 year interval to 1 in 15 year interval is 0.753%. Therefore, this increase is judged to be small.

### 5.2.6 Impact of Extension on Detection of Steel Liner Corrosion that Leads to Leakage

An estimate of the likelihood and risk implications of corrosion-induced leakage of the steel liners occurring and going undetected during the extended test interval is evaluated using a methodology similar to the Calvert Cliffs liner corrosion analysis [Reference 5]. The Calvert Cliffs analysis was performed for a concrete cylinder and dome and a concrete basemat, each with a steel liner.

The following approach is used to determine the change in likelihood, due to extending the ILRT, of detecting corrosion of the containment steel liner. This likelihood is then used to determine the resulting change in risk. Consistent with the Calvert Cliffs analysis, the following issues are addressed:

- Differences between the containment basemat and the containment cylinder and dome
- The historical steel liner flaw likelihood due to concealed corrosion
- The impact of aging
- The corrosion leakage dependency on containment pressure
- The likelihood that visual inspections will be effective at detecting a flaw

<u>Assumptions</u>

- Consistent with the Calvert Cliffs analysis, a half failure is assumed for basemat concealed liner corrosion due to the lack of identified failures (See Table 5-15, Step 1).
- In the 5.5 years following September 1996 when 10 CFR 50.55a started requiring visual inspection, there were three events where a through wall hole in the containment liner was identified. These are Brunswick 2 on 4/27/99, North Anna 2 on 9/23/99, and D. C. Cook 2 in November 1999. The corrosion associated with the Brunswick event is believed to have started from the coated side of the containment liner. Although HNP has a different containment type, this event could potentially occur at HNP (i.e., corrosion starting on the coated side of containment). Construction material embedded in the concrete may have contributed to the corrosion. The corrosion at North Anna is believed to have started on the uninspectable side of containment due to wood imbedded in the concrete during construction. The D. C. Cook event is associated with an inadequate repair of a hole drilled through the liner during construction. Since the hole was created during construction and not caused by corrosion, this event does not

apply to this analysis. Based on the above data, there are two corrosion events from the 5.5 years that apply to HNP.

- Consistent with the Calvert Cliffs analysis, the estimated historical flaw probability is also limited to 5.5 years to reflect the years since September 1996 when 10 CFR 50.55a started requiring visual inspection. Additional success data was not used to limit the aging impact of this corrosion issue, even though inspections were being performed prior to this date (and have been performed since the time frame of the Calvert Cliffs analysis) (See Table 5-4, Step 1).
- Consistent with the Calvert Cliffs analysis, the steel liner flaw likelihood is assumed to double every five years. This is based solely on judgment and is included in this analysis to address the increased likelihood of corrosion as the steel liner ages (See Table 5-15, Steps 2 and 3). Sensitivity studies are included that address doubling this rate every ten years and every two years.
- In the Calvert Cliffs analysis, the likelihood of the containment atmosphere reaching the outside atmosphere, given that a liner flaw exists, was estimated as 1.1% for the cylinder and dome, and 0.11% (10% of the cylinder failure probability) for the basemat. These values were determined from an assessment of the probability versus containment pressure. For HNP, the ILRT maximum pressure is 45 psig [References 44]. Probabilities of 1% for the cylinder and dome, and 0.1% for the basemat are used in this analysis, and sensitivity studies are included in Section 5.3.1 (See Table 5-15, Step 4).
- Consistent with the Calvert Cliffs analysis, the likelihood of leakage escape (due to crack formation) in the basemat region is considered to be less likely than the containment cylinder and dome region (See Table 5-15, Step 4).
- In the Calvert Cliffs analysis, it is noted that approximately 85% of the interior wall surface is accessible for visual inspections. Consistent with the Calvert Cliffs analysis, a 5% visual inspection detection failure likelihood given the flaw is visible and a total detection failure likelihood of 10% is used. To date, all liner corrosion events have been detected through visual inspection (See Table 5-15, Step 5).
- Consistent with the Calvert Cliffs analysis, all non-detectable containment failures are assumed to result in early releases. This approach avoids a detailed analysis of containment failure timing and operator recovery actions.

**Table 5-15 – Steel Liner Corrosion Base Case**

| Step | Description | Containment Cylinder and Dome (85%) | Containment Basemat (15%) |
|---|---|---|---|
| 1 | Historical liner flaw likelihood<br>Failure data: containment location specific<br>Success data: based on 70 steel-lined containments and 5.5 years since the 10CFR 50.55a requirements of periodic visual inspections of containment surfaces | Events: 2<br>(Brunswick 2 and North Anna 2)<br>2 / (70 x 5.5) = 5.19E-03 | Events: 0<br>Assume a half failure<br>0.5 / (70 x 5.5) = 1.30E-03 |
| 2 | Aged adjusted liner flaw likelihood During the 15-year interval, assume failure rate doubles every five years (14.9% increase per year). The average for the 5th to 10th year set to the historical failure rate. | Year — Failure rate<br>1 — 2.05E-03<br>average 5-10 — 5.19E-03<br>15 — 1.43E-02<br>15 year average = 6.44E-03 | Year — Failure rate<br>1 — 5.13E-04<br>average 5-10 — 1.30E-03<br>15 — 3.57E-03<br>15 year average = 1.61E-03 |
| 3 | Increase in flaw likelihood between 3 and 15 years Uses aged adjusted liner flaw likelihood (Step 2), assuming failure rate doubles every five years. | 0.71% (1 to 3 years)<br>4.14% (1 to 10 years)<br>9.66% (1 to 15 years) | 0.18% (1 to 3 years)<br>1.04% (1 to 10 years)<br>2.42% (1 to 15 years) |
| 4 | Likelihood of breach in containment given liner flaw | 1% | 0.1% |
| 5 | Visual inspection detection failure likelihood | 10%<br>5% failure to identify visual flaws plus 5% likelihood that the flaw is not visible (not through-cylinder but could be detected by ILRT).<br>All events have been detected through visual inspection. 5% visible failure detection is a conservative assumption. | 100%<br>Cannot be visually inspected |
| 6 | Likelihood of non-detected containment leakage (Steps 3 x 4 x 5) | 0.00071% (3 years)<br>0.71% x 1% x 10%<br>0.00414% (10 years)<br>4.18% x 1% x 10%<br>0.00966% (15 years)<br>9.66% x 1% x 10% | 0.00018% (3 years)<br>0.18% x 0.1% x 100%<br>0.00104% (10 years)<br>1.04% x 0.1% x 100%<br>0.00242% (15 years)<br>2.42% x 0.1% x 100% |

The total likelihood of the corrosion-induced, non-detected containment leakage is the sum of Step 6 for the containment cylinder and dome, and the containment basemat, as summarized below for HNP.

**Table 5-16 – Total Likelihood on Non-Detected Containment Leakage Due to Corrosion for HNP**

| Description |
|---|
| At 3 years: 0.00071% + 0.00018% = 0.00089% |
| At 10 years: 0.0041% + 0.00104% = 0.00517% |
| At 15 years: 0.00966% + 0.00242% = 0.01207% |

The above factors are applied to those core damage accidents that are not already independently LERF or that could never result in LERF.

The two corrosion events that were initiated from the non-visible (backside) portion of the containment liner used to estimate the liner flaw probability in the Calvert Cliffs analysis are assumed to be applicable to this containment analysis. These events, one at North Anna Unit 2 (September 1999) caused by timber embedded in the concrete immediately behind the containment liner, and one at Brunswick Unit 2 (April 1999) caused by a cloth work glove embedded in the concrete next to the liner, were initiated from the nonvisible (backside) portion of the containment liner. A search of the NRC website LER database identified two additional events have occurred since the Calvert Cliffs analysis was performed. In January 2000, a 3/16-inch circular through-liner hole was found at Cook Nuclear Plant Unit 2 caused by a wooden brush handle embedded immediately behind the containment liner. The other event occurred in April 2009, where a through-liner hole approximately 3/8-inch by 1-inch in size was identified in the Beaver Valley Power Station Unit 1 (BVPS-1) containment liner caused by pitting originating from the concrete side due to a piece of wood that was left behind during the original construction that came in contact with the steel liner [Reference 29]. Two other containment liner through-wall hole events occurred at Turkey Point Units 3 and 4 in October 2010 and November 2006, respectively. However, these events originated from the visible side caused by the failure of the coating system, which was not designed for periodic immersion service, and are not considered to be applicable to this analysis. More recently, in October 2013, some through-wall containment liner holes were identified at BVPS-1, with a combined total area of approximately 0.395 square inches. The cause of these through-wall liner holes was attributed to corrosion originating from the outside concrete surface due to the presence of rayon fiber foreign material that was left behind during the original construction and was contacting the steel liner. For risk evaluation purposes, these five total corrosion events occurring in 66 operating plants with steel containment liners over a 17.1 year period from September 1996 to October 4, 2013 (i.e., 5/(66*17.1) = 4.43E-03) are bounded by the estimated historical flaw probability based on the two events in the 5.5 year period of the Calvert Cliffs analysis (i.e., 2/(70*5.5) = 5.19E-03) incorporated in the EPRI guidance [Reference 24].

### 5.2.7 Impact from External Events Contribution

An assessment of the impact of external events is performed. The primary purpose for this investigation is the determination of the total LERF following an increase in the ILRT testing interval from 3 in 10 years to 1 in 15 years.

The Revision 5 Fire PRA model with changes incorporated for the Essential Services Chilled Water System Allowed Out of Service Time LAR was used to obtain the fire CDF and LERF values [Reference 18]. To reduce conservatism in the model, the methodology of subtracting existing LERF from CDF is also applied to the Fire PRA model. The following shows the calculation for Class 3b:

$$Freq_{class3b} = P_{class3b} * (CDF - LERF) = \frac{0.5}{218} * (4.48E\text{-}5 - 3.21E\text{-}6) = 9.54\text{E-}08$$

$$Freq_{class3b10yr} = \frac{10}{3} * P_{class3b} * (CDF - LERF) = \frac{10}{3} * \frac{0.5}{218} * (4.48E\text{-}5 - 3.21E\text{-}6) = 3.18\text{E-}07$$

$$Freq_{class3b15yr} = \frac{15}{3} * P_{class3b} * (CDF - LERF) = 5 * \frac{0.5}{218} * (4.48E\text{-}5 - 3.21E\text{-}6) = 4.77\text{E-}07$$

The 2014 Seismic Reevaluations for operating reactor sites [Reference 30] states the conclusions reached in 2010 by GI-199 [Reference 28] remain valid for estimating Seismic CDF at plants in the Central and Eastern United States, which includes HNP. EPRI guidance [Reference 30] on recent seismic evaluations states, "EPRI does not recommend using any very conservative approaches to estimate the SCDF such as use of the maximum SCDFs calculated at any one frequency. This type of bounding approach is overly conservative and judged to not provide realistic risk estimates consistent with SCDFs calculated in actual SPRAs." Therefore, the simple average of 1.40E-06 reported in Table D-1 of GI-199 [Reference 28] is used for the Seismic CDF. Since no Seismic LERF value is calculated, it is assumed the LERF/CDF ratio will be similar for seismic risk as for internal events risk. Applying the internal event LERF/CDF ratio to the seismic CDF yields an estimated seismic LERF of 2.50E-07, as shown by the equations below.

$$\mathrm{LERF_{Seismic}} \approx \mathrm{CDF_{Seismic}} * \mathrm{LERF_{IE}} / \mathrm{CDF_{IE}} = 1.40\text{E-}06 * 1.55\text{E-}06 / 8.65\text{E-}06 = 2.50\text{E-}07$$

Subtracting seismic LERF from CDF, the Class 3b frequency can be calculated by the following formulas:

$$Freq_{class3b} = P_{class3b} * (CDF - LERF) = \frac{0.5}{218} * (1.40E\text{-}6 - 2.50E\text{-}7) = 2.64\text{E-}09$$

$$Freq_{class3b10yr} = \frac{10}{3} * P_{class3b} * (CDF - LERF) = \frac{10}{3} * \frac{0.5}{218} * (1.40E\text{-}6 - 2.50E\text{-}7) = 8.79\text{E-}09$$

$$Freq_{class3b15yr} = \frac{15}{3} * P_{class3b} * (CDF - LERF) = 5 * \frac{0.5}{218} * (1.40E\text{-}6 - 2.50E\text{-}7) = 1.32\text{E-}08$$

The fire and seismic contributions to Class 3b frequencies are then combined to obtain the total external event contribution to Class 3b frequencies. The change in LERF is calculated for the 1 in 10 year and 1 in 15 year cases and the change defined for the external events in Table 5-17.

**Table 5-17 – Unit 1 HNP External Event Impact on ILRT LERF Calculation**

| Hazard | EPRI Accident Class 3b Frequency | | | LERF Increase (from 3 per 10 years to 1 per 15 years) |
|---|---|---|---|---|
| | 3 per 10 year | 1 per 10 year | 1 per 15 years | |
| External Events | 9.80E-08 | 3.27E-07 | 4.90E-07 | 3.92E-07 |
| Internal Events | 1.63E-08 | 5.43E-08 | 8.15E-08 | 6.52E-08 |
| Combined | 1.14E-07 | 3.81E-07 | 5.72E-07 | 4.57E-07 |

The internal event results are also provided to allow a composite value to be defined. When both the internal and external event contributions are combined, the increase due to increasing the interval from 10 to 15 years is 1.91E-7; the total change in LERF due to increasing the ILRT interval from 3 to 15 years is 4.57E-7, which meets the guidance for small change in risk, as it exceeds 1.0E-7/yr and remains less than a 1.0E-6 change in LERF. For this change in LERF to be acceptable, total LERF must be less than 1.0E-5. The total LERF is calculated below:

$$\mathrm{LERF} = \mathrm{LERF_{internal}} + \mathrm{LERF_{fire}} + \mathrm{LERF_{seismic}} + \mathrm{LERF_{class3Bincrease}}$$

$$\mathrm{LERF_{15yr}} = 1.55\text{E-}6/\mathrm{yr} + 3.21\text{E-}6/\mathrm{yr} + 2.50\text{E-}7/\mathrm{yr} + 4.57\text{E-}7/\mathrm{yr} = 5.46\text{E-}6/\mathrm{yr}$$

As specified in Regulatory Guide 1.174 [Reference 4], since the total LERF is less than 1.0E-05, it is acceptable for the ΔLERF to be between 1.0E-07 and 1.0E-06.

#### 5.2.7.1 Screened External Hazards

Several "other" external events were evaluated in the HNP IPEEE [Reference 34]. Detailed evaluations were performed for floods, high winds, transportation accidents, and nearby facility accidents. The IPEEE concluded that none of the "other" external events pose a significant threat to the plant [Reference 34]. Since the time the IPEEE was performed, FLEX has been installed at HNP to provide additional accident mitigation capabilities [Reference 42]. External floods have been reevaluated in response to Near-Term Task Force (NTTF) Recommendation 2.1, and HNP concluded no external flooding onsite will affect any key structures, systems, or components or key safety functions at HNP [Reference 33].

Consistent with Reference 34, Reference 44, and Reference 45, high winds are not considered a significant hazard for HNP and have been screened as a negligible contributor from the ILRT Extension PRA evaluation. Assessment of high winds is discussed in the HNP UFSAR Section 3.3 [Reference 32] and IPEEE Section 5.3 [Reference 34]. The plant structures are designed to withstand the design wind load and the effects of tornado missiles. Thus, design basis for this event meets the criteria in the 1975 Standard Review Plan (SRP). Additionally, the most likely damage would be a loss of offsite power that is already included in the internal events model. Therefore, high winds are screened out from this analysis.

No significant changes have been made that would affect the IPEEE evaluations of highway transportation, railroads, waterways, pipelines, military facilities, or industrial facilities. This evaluation is maintained in Section 2.2 and Section 3.5 of the UFSAR [Reference 32]. According to the Federal Aviation Administration's Air Traffic Activity System, air traffic at the Raleigh-Durham Airport, the closest airport serving commercial airlines, has slightly decreased since the time of the IPEEE. Based on the information summarized here from the IPEEE [Reference 34] and maintained in the UFSAR [Reference 32], these hazards are screened from this analysis.

### 5.2.8 Defense-In-Depth Impact

Regulatory Guide 1.174, Revision 3 [Reference 4] describes an approach that is acceptable for developing risk-informed applications for a licensing basis change that considers engineering issues and applies risk insights. One of the considerations included in RG 1.174 is Defense in Depth. Defense in Depth is a safety philosophy that employs successive compensatory measures to prevent accidents or mitigate damage if a malfunction, accident, or naturally caused event occurs at a nuclear facility. The following seven considerations as presented in RG 1.174, Revision 3, Section C.2.1.1.2 will serve to evaluate the proposed licensing basis change for overall impact on Defense in Depth.

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

The use of the risk metrics of LERF, population dose, and conditional containment failure probability collectively ensures the balance between prevention of core damage, prevention of containment failure, and consequence mitigation is preserved. The change in LERF is "very small" with respect to internal events and "small" when including external events per RG 1.174, and the change in population dose and CCFP are "small" as defined in this analysis and consistent with NEI 94-01 Revision 3-A.

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

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

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

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

4. Preserve adequate defense against potential CCFs.

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

5. Maintain multiple fission product barriers.

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

6. Preserve sufficient defense against human errors.

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

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

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

## 5.3 Sensitivities

### 5.3.1 Potential Impact from Steel Liner Corrosion Likelihood

A quantitative assessment of the contribution of steel liner corrosion likelihood impact was performed for the risk impact assessment for extended ILRT intervals. As a sensitivity run, the internal event CDF was used to calculate the Class 3b frequency. The impact on the Class 3b frequency due to increases in the ILRT surveillance interval was calculated for steel liner corrosion likelihood using the relationships described in Section 5.2.6. The EPRI Category 3b frequencies for the 3 per 10-year, 10-year, and 15-year ILRT intervals were quantified using the internal events CDF. The change in the LERF, change in CCFP, and change in Annual Dose Rate due to extending the ILRT interval from 3 in 10 years to 1 in 10 years, or to 1 in 15 years are provided in Table 5-18 – Table 5-20. The steel liner corrosion likelihood was increased by a factor of 1000, 10000, and 100000. Except for extreme factors of 10000 and 100000, the corrosion likelihood is relatively insensitive to the results.

**Table 5-18 – Steel Liner Corrosion Sensitivity Case: 3B Contribution**

| | 3b Frequency (3-per-10 year ILRT) | 3b Frequency (1-per-10 year ILRT) | 3b Frequency (1-per-15 year ILRT) | LERF Increase (3-per-10 to 1-per-10) | LERF Increase (3-per-10 to 1-per-15) | LERF Increase (1-per-10 to 1-per-15) |
|---|---|---|---|---|---|---|
| Corrosion Likelihood X 1 | 1.63E-08 | 5.43E-08 | 8.15E-08 | 3.80E-08 | 6.52E-08 | 2.72E-08 |
| Corrosion Likelihood X 1000 | 1.64E-08 | 5.71E-08 | 9.13E-08 | 4.07E-08 | 7.49E-08 | 3.42E-08 |
| Corrosion Likelihood X 10000 | 1.77E-08 | 8.24E-08 | 1.80E-07 | 6.47E-08 | 1.62E-07 | 9.74E-08 |
| Corrosion Likelihood X 100000 | 3.08E-08 | 3.35E-07 | 1.06E-06 | 3.05E-07 | 1.03E-06 | 7.30E-07 |

**Table 5-19 –Steel Liner Corrosion Sensitivity: CCFP**

| | CCFP (3-per-10 year ILRT) | CCFP (1-per-10 year ILRT) | CCFP (1-per-15 year ILRT) | CCFP Increase (3-per-10 to 1-per-10) | CCFP Increase (3-per-10 to 1-per-15) | CCFP Increase (1-per-10 to 1-per-15) |
|---|---|---|---|---|---|---|
| Corrosion Likelihood X 1 | 5.83E-01 | 5.88E-01 | 5.91E-01 | 4.39E-03 | 7.53E-03 | 3.14E-03 |
| Corrosion Likelihood X 1000 | 5.83E-01 | 5.88E-01 | 5.91E-01 | 4.43E-03 | 7.60E-03 | 3.17E-03 |
| Corrosion Likelihood X 10000 | 5.83E-01 | 5.88E-01 | 5.92E-01 | 4.79E-03 | 8.20E-03 | 3.42E-03 |
| Corrosion Likelihood X 100000 | 5.85E-01 | 5.93E-01 | 5.99E-01 | 8.30E-03 | 1.42E-02 | 5.93E-03 |

**Table 5-20 –Steel Liner Corrosion Sensitivity: Dose Rate**

| | Dose Rate (3-per-10 year ILRT) | Dose Rate (1-per-10 year ILRT) | Dose Rate (1-per-15 year ILRT) | Dose Rate Increase (3-per-10 to 1-per-10) | Dose Rate Increase (3-per-10 to 1-per-15) | Dose Rate Increase (1-per-10 to 1-per-15) |
|---|---|---|---|---|---|---|
| Corrosion Likelihood X 1 | 9.62E-03 | 3.21E-02 | 4.81E-02 | 2.24E-02 | 3.85E-02 | 1.60E-02 |
| Corrosion Likelihood X 1000 | 9.70E-03 | 3.23E-02 | 4.85E-02 | 2.26E-02 | 3.88E-02 | 1.62E-02 |
| Corrosion Likelihood X 10000 | 1.05E-02 | 3.49E-02 | 5.24E-02 | 2.44E-02 | 4.19E-02 | 1.75E-02 |
| Corrosion Likelihood X 100000 | 1.82E-02 | 6.06E-02 | 9.09E-02 | 4.24E-02 | 7.27E-02 | 3.03E-02 |

### 5.3.2 Expert Elicitation Sensitivity

Another sensitivity case on the impacts of assumptions regarding pre-existing containment defect or flaw probabilities of occurrence and magnitude, or size of the flaw, is performed as described in Reference 24. In this sensitivity case, an expert elicitation was conducted to develop probabilities for pre-existing containment defects that would be detected by the ILRT only based on the historical testing data.

Using the expert knowledge, this information was extrapolated into a probability-versus-magnitude relationship for pre-existing containment defects [Reference 24]. The failure mechanism analysis also used the historical ILRT data augmented with expert judgment to develop the results. Details of the expert elicitation process and results are contained in Reference 24. The expert elicitation process has the advantage of considering the available data for small leakage events, which have occurred in the data, and extrapolate those events and probabilities of occurrence to the potential for large magnitude leakage events.

The expert elicitation results are used to develop sensitivity cases for the risk impact assessment. Employing the results requires the application of the ILRT interval methodology using the expert elicitation to change the probability of pre-existing leakage in the containment.

The baseline assessment uses the Jeffreys non-informative prior and the expert elicitation sensitivity study uses the results of the expert elicitation. In addition, given the relationship between leakage magnitude and probability, larger leakage that is more representative of large early release frequency, can be reflected. For the purposes of this sensitivity, the same leakage magnitudes that are used in the basic methodology (i.e., 10 $L_a$ for small and 100 $L_a$ for large) are used here. Table 5-21 presents the magnitudes and probabilities associated with the Jeffreys non-informative prior and the expert elicitation used in the base methodology and this sensitivity case.

**Table 5-21 – HNP Summary of ILRT Extension Using Expert Elicitation Values (from Reference 24)**

| Leakage Size ($L_a$) | Expert Elicitation Mean Probability of Occurrence | Percent Reduction |
|---|---|---|
| 10 | 3.88E-03 | 86% |
| 100 | 2.47E-04 | 91% |

Taking the baseline analysis and using the values provided in Table 5-10 and Table 5-11 for the expert elicitation sensitivity yields the results in Table 5-22.

**Table 5-22 – HNP Summary of ILRT Extension Using Expert Elicitation Values**

| Accident Class | ILRT Interval | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 3 per 10 Years | | | | 1 per 10 Years | | 1 per 15 Years | |
| | Base Frequency | Adjusted Base Frequency | Dose (person-rem) | Dose Rate (person-rem/yr) | Frequency | Dose Rate (person-rem/yr) | Frequency | Dose Rate (person-rem/yr) |
| 1 | 3.62E-06 | 3.59E-06 | 4.37E+03 | 1.57E-02 | 3.52E-06 | 1.54E-02 | 3.48E-06 | 1.52E-02 |
| 2 | 2.31E-08 | 2.31E-08 | 2.24E+06 | 5.19E-02 | 2.31E-08 | 5.19E-02 | 2.31E-08 | 5.19E-02 |
| 3a | N/A | 2.76E-08 | 4.37E+04 | 1.20E-03 | 9.19E-08 | 4.01E-03 | 1.38E-07 | 6.02E-03 |
| 3b | N/A | 1.75E-09 | 4.37E+05 | 7.66E-04 | 5.85E-09 | 2.55E-03 | 8.77E-09 | 3.83E-03 |
| 7 | 2.24E-06 | 2.24E-06 | 1.72E+06 | 3.86E+00 | 2.24E-06 | 3.86E+00 | 2.24E-06 | 3.86E+00 |
| 8 | 2.76E-06 | 2.76E-06 | 2.82E+06 | 7.79E+00 | 2.76E-06 | 7.79E+00 | 2.76E-06 | 7.79E+00 |
| Totals | 8.65E-06 | 8.65E-06 | 7.27E+06 | 1.17E+01 | 8.65E-06 | 1.17E+01 | 8.65E-06 | 1.17E+01 |
| ΔLERF (3 per 10 yrs base) | N/A | | | | 4.09E-09 | | 7.02E-09 | |
| ΔLERF (1 per 10 yrs base) | N/A | | | | N/A | | 2.92E-09 | |
| CCFP | 58.15% | | | | 58.20% | | 58.23% | |

The results illustrate how the expert elicitation reduces the overall change in LERF and the overall results are more favorable with regard to the change in risk.

# 6.0 RESULTS

The results from this ILRT extension risk assessment for HNP are summarized in Table 6-1.

**Table 6-1 – ILRT Extension Summary**

| Class | Dose (person-rem) | Base Case 3 in 10 Years | | Extend to 1 in 10 Years | | Extend to 1 in 15 Years | |
|---|---|---|---|---|---|---|---|
| | | CDF/Year | Person-Rem/Year | CDF/Year | Person-Rem/Year | CDF/Year | Person-Rem/Year |
| 1 | 4.37E+03 | 3.54E-06 | 1.55E-02 | 3.35E-06 | 1.46E-02 | 3.21E-06 | 1.40E-02 |
| 2 | 2.24E+06 | 2.31E-08 | 5.19E-02 | 2.31E-08 | 5.19E-02 | 2.31E-08 | 5.19E-02 |
| 3a | 4.37E+04 | 6.55E-08 | 2.86E-03 | 2.18E-07 | 9.53E-03 | 3.27E-07 | 1.43E-02 |
| 3b | 4.37E+05 | 1.63E-08 | 7.12E-03 | 5.43E-08 | 2.37E-02 | 8.15E-08 | 3.56E-02 |
| 7 | 1.72E+06 | 2.24E-06 | 3.86E+00 | 2.24E-06 | 3.86E+00 | 2.24E-06 | 3.86E+00 |
| 8 | 2.82E+06 | 2.76E-06 | 7.79E+00 | 2.76E-06 | 7.79E+00 | 2.76E-06 | 7.79E+00 |
| **Total** | | **8.65E-06** | **1.17E+01** | **8.65E-06** | **1.17E+01** | **8.65E-06** | **1.18E+01** |
| **ILRT Dose Rate from 3a and 3b** | | | | | | | |
| ΔTotal Dose Rate | From 3 Years | N/A | | 2.24E-02 | | 3.85E-02 | |
| | From 10 Years | N/A | | N/A | | 1.60E-02 | |
| %ΔDose Rate | From 3 Years | N/A | | 0.19% | | 0.33% | |
| | From 10 Years | N/A | | N/A | | 0.14% | |
| **3b Frequency (LERF)** | | | | | | | |
| ΔLERF | From 3 Years | N/A | | 3.80E-08 | | 6.52E-08 | |
| | From 10 Years | N/A | | N/A | | 2.72E-08 | |
| **CCFP %** | | | | | | | |
| ΔCCFP% | From 3 Years | N/A | | 0.439% | | 0.753% | |
| | From 10 Years | N/A | | N/A | | 0.314% | |

# 7.0 CONCLUSIONS AND RECOMMENDATIONS

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

- Regulatory Guide 1.174 [Reference 4] provides guidance for determining the risk impact of plant-specific changes to the licensing basis. Regulatory Guide 1.174 defines very small changes in risk as resulting in increases of CDF less than 1.0E-06/year and increases in LERF less than 1.0E-07/year. Since the ILRT does not impact CDF, the relevant criterion is LERF. The increase in LERF resulting from a change in the Type A ILRT test interval from 3 in 10 years to 1 in 15 years is estimated as 6.52E-8/year using the EPRI guidance; this value increases negligibly if the risk impact of corrosion-induced leakage of the steel liners occurring and going undetected during the extended test interval is included. Therefore, the estimated change in LERF is determined to be “very small” using the acceptance guidelines of Regulatory Guide 1.174 [Reference 4]. The risk change resulting from a change in the Type A ILRT test interval from 3 in 10 years to 1 in 15 years bounds the 1 in 10 years to 1 in 15 years risk change. Considering the increase in LERF resulting from a change in the Type A ILRT test interval from 1 in 10 years to 1 in 15 years is estimated as 2.72E-8, the risk increase is “very small” using the acceptance guidelines of Regulatory Guide 1.174 [Reference 4].
- When external event risk is included, the increase in LERF resulting from a change in the Type A ILRT test interval from 3 in 10 years to 1 in 15 years is estimated as 4.57E-7/year using the EPRI guidance, and total LERF is 5.46E-6/year. As such, the estimated change in LERF is determined to be “small” using the acceptance guidelines of Regulatory Guide 1.174 [Reference 4]. The risk change resulting from a change in the Type A ILRT test interval from 3 in 10 years to 1 in 15 years bounds the 1 in 10 years to 1 in 15 years risk change. When external event risk is included, the increase in LERF resulting from a change in the Type A ILRT test interval from 1 in 10 years to 1 in 15 years is estimated as 1.91E-7 and the total LERF is 5.20E-6. Therefore, the risk increase is “small” using the acceptance guidelines of Regulatory Guide 1.174 [Reference 4].
- The effect resulting from changing the Type A test frequency to 1-per-15 years, measured as an increase to the total integrated plant risk for those accident sequences influenced by Type A testing, is 0.038 person-rem/year. NEI 94-01 [Reference 1] states that a small population dose is defined as an increase of ≤ 1.0 person-rem per year, or ≤ 1% of the total population dose, whichever is less restrictive for the risk impact assessment of the extended ILRT intervals. The results of this calculation meet these criteria. Moreover, the risk impact for the ILRT extension when compared to other severe accident risks is negligible.
- The increase in the conditional containment failure probability from the 3 in 10 year interval to 1 in 15 year interval is 0.753%. NEI 94-01 [Reference 1] states that increases in CCFP of ≤ 1.5% is small. Therefore, this increase is judged to be small.

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

<u>Previous Assessments</u>

The NRC in NUREG-1493 [Reference 6] has previously concluded that:

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

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

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

# A. PRA ACCEPTABILITY

## A.1. PRA Quality Statement for Permanent 15-Year ILRT Extension

The Duke Energy risk management process ensures that the applicable PRA models used in this application continue to reflect the as-built and as-operated plant for HNP. The process delineates the responsibilities and guidelines for updating the PRA models, and includes criteria for both regularly scheduled and interim PRA model updates. The process includes provisions for monitoring potential areas affecting the PRA models (e.g., due to changes in the plant, errors or limitations identified in the model, industry operational experience) for assessing the risk impact of unincorporated changes, and for controlling the model and associated computer files. The process will assess the impact of these changes on the plant PRA model in a timely manner but no longer than once every two refueling outages.

HNP has full-power internal events, internal floods, and fire PRA models. The HNP models are highly detailed and include a wide variety of initiating events, modeled systems, operator actions, and common cause events. The PRA quantification process used is based on the large linked fault tree methodology, which is a well-known and accepted methodology in the industry. The models are maintained and quantified using the EPRI Risk & Reliability suite of software programs.

The following sections describe the specific peer review history, results, and open F&Os associated with each PRA model used in this analysis. The Type A test surveillance frequency change PRA analysis is judged to meet the technical adequacy requirements for the application.

## A.2. Internal Events and Internal Flooding PRA

The HNP internal events PRA model was subject to a self-assessment and a full-scope peer review conducted in 2002 in accordance with guidance in NEI-00-02, Industry PRA Peer Review Process. In 2006, a self-assessment was conducted to identify supporting requirements that did not meet Category II of the ASME Standard RA-Sb-2005 and RG 1.200 Rev. 1. In 2007, a focused scope industry peer review against two elements was conducted as a follow up to the self-assessment against ASME Standard RA-Sb-2005 and RG 1.200 Rev. 1. In July 2017, a focused scope industry peer review was conducted against one model area that was upgraded.

The Internal Events PRA model was peer reviewed in 2002 by the PWR Owners Group (PWROG) prior to the issuance of Regulatory Guide 1.200. As a result, self-assessments have been conducted by Duke Energy of the Internal Events PRA model in accordance with Appendix B of RG 1.200 Revision 2 [Reference 36] to address the PRA technical adequacy requirements not considered in the 2002 peer review. The Internal Events PRA technical adequacy (including the 2002 peer review and self-assessment results) has previously been reviewed by the NRC in previous requests noted below:

- License Amendment Regarding Risk-Informed Justifications for the Relocation of Specific Surveillance Frequency Requirements to a Licensee-Controlled Program, November 29, 2016 ADAMS Accession No. ML16200A285 [Reference 27]
- License Amendment Regarding Adoption of National Fire Protection Association Standard 805, June 28, 2010 ADAMS Accession No. ML10750602 [Reference 43]

Upgrades that have occurred since the PWROG peer review in 2002 have been reviewed in accordance with the peer review process. There are no unreviewed PRA upgrades as defined by the ASME PRA Standard RA-Sa-2009 [Reference 37] in the Internal Events PRA model.

The HNP internal flood PRA model was subject to a self-assessment and a full-scope (covering all internal flood SRs) peer review conducted in August 2014 against RG 1.200 Revision 2.

Closed findings were reviewed and closed in March 2017 for the Internal Events and Internal Flood models as a pilot for the process documented in the draft of Appendix X to NEI 05-04, NEI 07-12, and NEI 12-13, “Close-out of Facts and Observations” (F&Os) published at the time of the review. NRC staff observed the pilot closure on-site event held January 31 through February 1, 2017. An assessment has been performed to determine the impact of changes to the guidance between the closure event and the final version endorsed by NRC. The main deltas identified are related to 1) utility and review team’s documented determination and justification if each finding resolution is an upgrade verses maintenance update, and 2) the assessment team’s confirmation that for the closed F&Os, the aspects of the underlying SRs in ASME/ANS RA-Sa-2009 that were previously not met, or met at CC-I, are now met or met at CC-II. The utility portion of the upgrade versus maintenance assessment was completed globally and did not identify any resolutions as an upgrade. Additionally, the review team determined none of the resolutions were upgrades and this is documented in the final report. The assessment team confirmed resolution of the findings allowed re-categorization of capability categories to meet or met at CC-II, as applicable. The results of this review have been documented and are available for NRC audit.

There are no open findings for the HNP Internal Events model. Ten Internal Flooding PRA F&Os remain open and are dispositioned in Section A.2.1. All the Finding Level F&Os have been determined to not significantly affect the ILRT extension analysis.

### A.2.1 Disposition of Open Internal Flooding PRA Findings and Observations (F&Os)

| Finding Number | Supporting Requirement(s) | Capability Category (CC) | Description | Disposition for ILRT Extension |
|---|---|---|---|---|
| 1-9 | IFSN-A4 | Not Met | Finding: Flow through floor drains is calculated and documented in internal flooding PRA. However, it appears that flow is incorrectly calculated for situations when multiple floor drains are connected to one drain line.<br><br>The calculations shown in HNP-F-PSA-0091 show a capacity per floor drain and the total capacity in each flood area is the average capacity per drain multiplied by the number of floor drains. However, no discussion of how multiple drains are connected to common drain line is provided. When multiple drains flow through a common drain line, the flow from each successive drain greatly reduces the flow from each drain in the system.<br><br>From the F&O Closure team: Item is partially closed. Section 6.3.6 of and Attachment 4 to Calculation HNP-F/PSA-0091 document the revised analysis of the drainage system in RAB. Based on this analysis for RAB, for spray events resulting in a flow rate of less than 100 gpm, the resulting flood is within the capacity of the drain system and will not result in submergence of SSCs in the flood originating compartment. For scenarios other than sprays, no credit is taken in the flood propagation analysis for beneficial removal of water from a flood compartment through the floor drains. For buildings other than RAB, however, drain analysis was not performed and no qualitative evaluation was documented. In particular, upper elevations in the Turbine Building (TB) could potentially flow downward to the basement and caused additional damage to PRA equipment in the TB basement (e.g., condensate pumps, etc.). | This F&O is partially closed.<br><br>The analysis of the floor drainage system was revised for the Reactor Auxiliary Building (RAB), and the supporting requirement was evaluated to be Met for the RAB by the F&O Closure team. For buildings other than the RAB, however, the qualitative evaluation that was done was not included in the documentation. Buildings other than the RAB are open to the outside so water will not accumulate from backflow through floor drains. This is a documentation issue and does not impact the ILRT extension application. |
| 1-18 | IFSN-B3 | Not Met | The assessment of door failure heights is evaluated in the internal flooding PRA. The analysis of doors is based entirely on assumptions; however, these assumptions are not listed in the assumptions section of the documentation.<br><br>The standard requires that assumptions be listed and characterized. Civil Calculation HNP-C/RAB-1008, Rev. 0 provides a Harris-specific analysis that indicates a standard | Door failure assumptions based on a plant Civil calculation were included, scenarios were reassessed, and documentation was updated. The F&O Closure team, however, stated that the analysis did not include all critical failure modes (specifically, did not include warping of the door resulting in failure to latch), and that |

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|---|---|---|---|---|
| | | | 3'X7" tornado door can withstand a sustained pressure of 1.5 psig away from the doorframe with a safety factor of 4. Based on this pressure loading, it was estimated that the door failure differential flood height is at least 6.5 feet (note that the estimated door failure differential flood height at Fort Calhoun was even higher). However, the critical failure modes evaluated in Civil Calculation HNP-C/RAB-1008, Rev. 0 only include failures of door frame, door latch, door hinge plate, and door hinge pin. The analysis did not consider warping of door resulting in failure to latch. For fire doors, the warping failure mode may be more vulnerable than the other failure modes, based on the analysis of fire door manufacturer test data for another U.S. nuclear plant.<br><br>Also, the evaluation performed in Civil Calculation HNP-C/RAB-1008, Rev. 0 is for tornado door which is considered to be stronger than the standard fire doors and non-fire rated normal egress doors. As such, the door failure criterion of 6.5 feet of differential flood height should not be applied to the fire doors and normal egress doors.<br><br>It is not clear if this door failure differential flood height was applied to the RAB doors. If yes, it is inappropriate. If no, the use of the criteria of 1 foot/3 feet mentioned in the EPRI IFPRA guidance report appears to be too conservative for the RAB fire doors. | the door failure criteria used may not be appropriate for all door types. The team recommended that the specific criteria used for door failure be re-examined to ensure that realistic criteria is being used. Reexamination is not expected to significantly change the timing or impacts of any flooding sequence (because of the very large rooms at HNP), and the impact to the ILRT extension analysis would be minimal. |
| 1-7 | IFSN-A2 | CC-II | Flood alarms are identified in the HRA analyses. However, the alarms are not specifically identified, nor are the alarms correlated to the flood source that causes the flooding event.<br><br>Table 7-2 of HNP-F/PSA-0094 lists alarms and indications that can be used to identify the flooding conditions in each of the flood compartments. However, the alarms and indications listed in Table 7-2 may not be always sufficient or clear (with the exception of Fire Water system, Chilled Water System, CCW, Circulating Water system, CVCS, SW, etc.) for use to identify the specific flood sources that cause the flooding conditions. SR IFSN-A2 requires the identification of flood alarms for each flood source and each flood area. | This F&O is partially closed.<br><br>The specific alarms that might be available to indicate floods or leaks in a specific compartment have been added which results in this Supporting Requirement being MET. Documentation was revised to list the alarms or indications of leaks or flooding per compartment as well as the specific alarms to aid in flood identification in a particular area.<br><br>The F&O closure team suggested, however, that the documentation might not be sufficient or clear (for a subset of systems) to identify the specific source that caused a flood. Duke Energy disagrees with the closure team's |

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| | | | | suggestion. HNP's Ops procedures are symptom based diagnostic procedures that are not tied to specific sources, and the indicators and alarms help the operator diagnose location and source of flood. Dominant sources have relevant alarms identified. There is no direct correlation between specific indications and alarms to specific flood sources. This is a documentation issue and does not impact the ILRT extension application. |
| 1-16 | IFSO-A4 | CC-II | Flooding events caused by human induced actions such as overfilling of tanks, flow diversion etc., are not addressed.<br><br>Maintenance-induced flooding frequencies by system and by flood compartment are evaluated in Section 6.8.3 of HNP-F/PSA-0093. It appears that the apportionment of the maintenance-induced flood frequencies by system to individual flood compartment is not performed in a manner consistent with the characteristics of the maintenance-induced flooding since it was done by the fraction of the system pipe length located in each flood compartment (although it follows exactly the guidance provided in EPRI Report 3002000079).<br><br>Maintenance-induced flooding scenarios are modeled in Sections 7.3.4 and 7.4.2 (as well as Attachment 9) of HNP-F/PSA-0092 for CCW heat exchangers and ESCW chillers in Flood Compartments FLC17b (RAB Elevation 236') and FLC18a (RAB Elevation 261'), respectively. Insufficient description is provided for the screening process used to select the maintenance-induced flooding scenarios included in the HNP IFPRA model.<br><br>With no proper justification, the maintenance-induced flooding frequencies apportioned to flood compartments other than the above two compartments were not accounted for in the IFPRA model. Since the frequency of maintenance induced flooding was derived from actual industry events, the frequencies apportioned to the flood compartments not selected for flood scenario modeling cannot be discarded unless it can be demonstrated that no open maintenance (including both PM and CM) can be performed on the subject fluid system during power operation. | This F&O is partially closed.<br><br>Plant level pipe break data on floods caused by human-induced maintenance errors and generic best estimates of associated plant level flood frequencies are included per Revision 3 of the EPRI pipe failure rate report (EPRI TR 3002000079). This includes human errors such as overfilling of tanks and flow diversion that result in floods. Human errors resulting in pressure boundary failures are included in direct failures involving failure of the pressure boundary caused by degradation mechanisms, loading conditions, and human error. To complement the generic data, HNP Operating Experience (OE) was reviewed for maintenance-induced flood events and documented in the IFPRA analysis.<br><br>The F&O closure team recommended that Duke Energy contact the author of the EPRI document to verify that the maintenance-induced flooding frequencies have been apportioned across flood compartment correctly, and that an additional sensitivity be performed on the potential impact of underestimating maintenance-induced flooding frequencies. Since maintenance-induced flooding is not a significant contributor to CDF/LERF, and since HNP is a single unit |

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| | | | | site with no shared systems, it is expected that additional validation of the results will not impact CDF/LERF; and therefore, the impact to the ILRT extension analysis would be minimal. |
| 1-19 | IEQU-A5 | CC-II | SR HR-G4 requires that the analyses be based on realistic estimates of the time to receive cues. The analyses used an assumption of 5 minutes to receive cues and assumed that service water low pressure alarms would be received. Experience shows that only for extremely large breaks would low pressure alarms be received and no analyses were seen that justified use of low pressure alarms for the HNP flood scenarios. No evaluation of the time to receive drain and sump alarms was provided. The basis for timing of the events analyzed was a scenario evaluated in the FSAR and that timing may not be applicable to the scenarios evaluated in the HNP IF PRA.<br><br>Analysis of RAB sump level alarms was documented in Table 7-4 of Calculation HNP-F/PSA-0094 for a spray event with a leak rate of 100 gpm and a flood event with a break flow of 2,000 gpm. However, the timings of the low pressure and high flow alarms are not addressed (i.e., no evaluation was found). The sump level alarms will support the identification of a flooding condition. However, it is not sufficient to support the identification of the specific flood source. No basis is provided to justify that 5 minutes are sufficient to diagnose the flood source and make decision on how to isolate the break. | This F&O is partially closed.<br><br>The HRA calculation has been revised to include the specific alarms that indicate floods in each flood area. Documentation of analysis of the RAB sump level alarms has been added, and the expected time for floor drain alarms from spray events in each flood area is included. The new information was incorporated into the HRA timing and scenario development per the suggested resolution. A simulator exercise was performed and observed to validate the assumptions, and performance shaping factors were based on the observed operator actions from the exercise.<br><br>The F&O Closure team, however, disagreed with the analysis, stating that the 5-minute time to recognize the cue and begin troubleshooting is not sufficient to support the identification of the specific flood source. They believe, despite the simulator exercise, that no basis is provided to justify the time allowed to diagnose and take initial action for any flood other than service water break. Duke Energy performed a sensitivity where the time to recognize the cues and begin identification was increased by a factor of 3, and there was minimal impact on the flooding results. This supporting requirement is MET, and no impact on the ILRT extension analysis is expected due to this recommendation. |

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| 2-3 | IFSN-A3 | CC-II | While the IFPRA documentation identifies the automatic and manual actions that have the ability to terminate or contain propagation for the four events requiring HRA, the documentation does not include similar actions for the remaining sources and areas.<br><br>Section 7.2 of Calculation HNP-F/PSA-0094 describes the automatic actions by the sump pumps as well as the manual operator actions to align the pumps to additional tanks. In addition, Table 7-2 of HNP-F/PSA-0094 identifies the manual operator actions that can be implemented to mitigate the flooding condition and propagation in the affected flood compartments. However, no manual action (e.g., break isolation) is identified for many of the flood compartments. Most of the manual actions identified are “opening doors to non-critical areas”. In Table 7-2, no considerations were given to isolation of the ruptured or leaking piping system by closing specific MOVs or manual valves. Nevertheless, isolation actions are modeled for many of the flood scenarios. They are just not listed in Table 7-2. | This F&O is partially closed.<br><br>Documentation has been added to describe the automatic actions by the sump pumps as well as the manual operator actions to align the pumps to additional tanks. In addition, the manual operator actions that can be implemented to mitigate the flooding condition and propagation in the affected flood compartments have been identified.<br><br>The F&O closure team, however, stated that no manual action (e.g., break isolation) is identified for many of the flood compartments. Most of the manual actions identified are proceduralized “opening doors to non-critical areas”. No considerations were given to isolation of the ruptured or leaking piping system by closing specific MOVs or manual valves. Nevertheless, isolation actions are modeled for many of the flood scenarios, but they are just not listed in the documentation. This is a documentation issue and does not impact the ILRT extension application. |
| 2-4 | IFSN-A6<br>IFEV-A5 | CC-I/II/III | Not all flood failure mechanisms are considered in the susceptibility of components to flood-induced failures. HELBs alone can result in high humidity and temperature which in turn will result in fire sprinkler discharge.<br><br>Attachment 10 to Calculation HNP-F/PSA-0091, Revision 1 provides the evaluation of such flood failure mechanisms as jet impingement, pipe whip, high temperature, high humidity, compartment pressurization, etc. that may result from the high energy line breaks (HELB). A criterion of 20 feet (for pipes with inner diameter less than 24”) or 10D (for pipes with inner diameter greater than 24”) was used to determine whether an SSC or fire protection sprinkler would be impacted by the effects of HELB. While the criteria of 20 feet/10D is adequate for the analysis of jet impingement and pipe whip, there is no analysis documented to demonstrate that the effects of high humidity and high temperature | This F&O is partially closed.<br><br>An analysis of high energy line breaks (HELBs) has been performed, and a new appendix describing the analysis has been added to the IFPRA documentation. The accident scenarios have been updated to include HELBs and the resulting effects. Jet impingement, pipe whip, high temperature and high humidity effects have been considered.<br><br>The F&O closure team stated, however, that additional analysis needs to be performed to demonstrate that the effects of high temperature and high humidity beyond the zone of influence (ZOI) for the HELB (i.e., 20 feet or 10X the pipe ID, |

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| | | | resulting from failure of high energy piping would not propagate beyond 20 feet/10D causing SSCs failures.<br><br>According to the HNP PRA staff, the only flood compartment in which not all PRA equipment is failed by a HELB scenario is a large room in the RAB, in which the 20 feet/10D zone of influence (ZOI) was applied. The temperature as a function of time in RAB at Elevation 261' after a MSLB in the steam tunnel (with door D10 to RAB open) was analyzed. The results indicate that, near the sprinkler header, the ceiling temperature reached is unlikely to activate the sprinklers. And, the peak temperature in the immediate proximity of Instrument Racks A1-R33 and A1-R22 (located directly outside of Door D10) would experience the direct effects of the steam plume coming through Door D10. Relative humidity in the area near Instrument Rack A1-R33 (El. 263.25'), which is bounding, reaches 100% for more than 20 minutes. Relative humidity values near the chillers and HVAC equipment peak at 100%.<br><br>The high energy lines in the RAB includes the steam supply line to the TDAFW pump and the charging lines. Although the steam lines for the TDAFW pump pass through RAB 236' elevation, the steam isolation valves located in the steam tunnel are normally closed during power operation, except during the TDAFW pump test. As such, this area is only exposed to the potential of a high energy line break during the TDAFW pump test.<br><br>The HNP IFPRA needs to verify that no PRA equipment would be impacted by high humidity or high temperature beyond the 20 feet / 10D ZOI, even for the rupture of the TDAFW pump steam supply line. | whichever is larger) would not cause additional PRA component damage in the large rooms at HNP. The ZOI calculation is based on SNL analyses and has been accepted by the NRC in previous industry submittals. The additional analysis is beyond the requirements of the Standard and will have no impact on the ILRT extension analysis. |
| 2-8 | IFEV-A7 | CC-I/II | While a great number of maintenance induced flooding frequencies were calculated, no evidence could be found that they were ever included in the model.<br><br>Maintenance-induced flooding scenarios are modeled in Sections 7.3.4 and 7.4.2 (as well as Attachment 9) for CCW heat exchangers and ESCW chillers in Flood Compartments FLC17b (RAB Elevation 236') and FLC18a (RAB Elevation 261'), respectively. Insufficient detailed description is provided for the screening process used to select the maintenance-induced flooding scenarios included in the IFPRA model. | In communications with Operations personnel, it was determined that the only maintenance-induced flooding events that could occur in Mode 1 are the CCW heat exchangers and the ESCW chillers. These two flood compartments' decision trees were modified to include Maintenance-Induced flooding as a failure mechanism, and scenarios were developed.<br><br>The F&O Closure Panel stated, however, that while these scenarios are indeed |

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| | | | During the onsite resolution review, it was indicated by the HNP Operations that open PM will not be performed on the CCW heat exchangers and ESCW chillers during power operation.<br><br>Since the frequency of maintenance induced flooding is derived from actual industry events, the frequencies apportioned to the flood compartments not selected for flood scenario modeling cannot be discarded unless it can be demonstrated that no open maintenance (including both PM and CM) can be performed on the subject fluid system during power operation. | modeled, insufficient detailed description is provided for the screening process used to select the maintenance-induced flooding scenarios. They further stated that since the frequency of maintenance induced flooding is derived from actual industry events, the frequencies apportioned to the flood compartments not selected for flood scenario modeling cannot be discarded unless it can be demonstrated that no open maintenance (including both PM and CM) can be performed on the subject fluid system during power operation. Additional documentation needs to be added on how the maintenance-induced flooding scenarios were selected and to assess whether or not the maintenance induced flooding frequency was apportioned properly. This is likely a documentation issue only; and therefore, would not impact the ILRT extension application. However, if the maintenance-induced flooding frequency is apportioned improperly, there may be a small impact to the CDF/LERF, which would have a minimal impact on the ILRT extension analysis numerical results but no impact on the conclusions due to the significant margin to the risk thresholds. |
| 2-11 | IFQU-A7 | CC-II | The FRANX software was used to quantify the HNP internal flooding model which utilizes the fault tree linking approach. SR QU-A2 of Section 2.2-7 states that the frequencies of individual sequences need to be estimated for CDF and this was not done for internal flooding.<br><br>Top CDF/LERF cutsets are presented in Table 5.1-1/5.2-1 and Attachments L/M of Calculation HNP-F/PSA-0095. The quantified CDF/LERF results of the top contributing flooding scenarios are given in Tables 5.1-2/5.2-2. Complete listing of the quantified CDF/LERF results for flooding scenarios are provided in Attachments J/K to Calculation HNP-F/PSA-0095. | This F&O is partially closed.<br><br>Top CDF/LERF cutsets are presented, and the top contributing flooding scenarios have been included in the documentation. A complete listing of the quantified CDF/LERF results for flooding scenarios are provided in Attachments to the documentation.<br><br>The F&O Closure team, however, indicated that documentation of quantified sequences for flooding scenarios are not provided. This is a documentation issue |

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| | | | Based on Duke PRA staff, FRANX includes calculation for accident sequences for LERF, but not for CDF.<br><br>Figures 5.6.1 and 5.6.2 show CDF by what is labeled as the sequence type, which are actually by IE, not sequence. In any event, estimates of the accident sequences are not included in the documentation. | and does not impact the ILRT extension application. |
| 2-12 | IFQU-A7 | CC-II | The FRANX software was used to quantify the HNP internal flooding model which utilizes the fault tree linking approach. The FRANX model is configured to apply recovery actions. A truncation of 1E-08 was applied for the CCDP which is considered sufficiently low to capture an appropriate number of cutsets to calculate an accurate CDF. The flooding model was quantified similarly to the internal events model which included the removal of cutsets with mutually exclusive events. The documentation states that the new HEPs associated with flooding were assumed to be independent of any other HEP in a scenario, however QU-C2 in Section 2.27 states that dependency between HEPs in a cutset or sequence must be assessed.<br><br>Section 7.7 of HNP-F/PSA-0094 indicates that there is no dependency between the flood mitigation actions and the subsequent operator actions carried over from the internal events PRA since the time between these actions are sufficiently long (essentially hours). However, a specific combination-by-combination evaluation of the dependency should be provided to demonstrate that indeed there is insufficient dependency between these two groups of operator actions. | This F&O is partially closed.<br><br>The HNP dependency analysis has been included in the IFPRA documentation. The documentation states that there is no dependency between the flood mitigation actions and the subsequent operator actions carried over from the internal events PRA since the time between these actions is sufficiently long (essentially hours).<br><br>The F&O Closure panel recommended that a specific, combination-by-combination evaluation of the dependency should be provided to demonstrate that indeed there is insufficient dependency between these two groups of operator actions. This is a documentation issue and does not impact the ILRT extension application. |

## A.3. Fire PRA

The HNP Fire PRA model was subject to a review conducted by the NRC during the NFPA 805 Pilot process and an additional focused scope industry peer review, both in 2008 in accordance with ANSI/ANS-58.23-2007. Since the reviews of the Fire PRA model were performed prior to the publication of RG 1.200 Rev. 2, a self-assessment was conducted to assess the differences between ANSI/ANS-58.23-2007 and the current version of the PRA standard, ASME/ANS RA-Sa-2009. That assessment confirmed there were no technical differences between the two versions of the standard.

Findings were reviewed and closed in October 2017 for the Fire PRA model using the process documented in Appendix X to NEI 05-04, NEI 07-12 and NEI 12-13, "Close-out of Facts and Observations" (F&Os) as accepted by NRC in the letter dated May 3, 2017 (ML17079A427) [Reference 38]. The results of this review have been documented and are available for NRC audit.

HNP has since updated the analysis to include the risk assessment of fires impacting structural steel members and the incorporation of obstructed plume model into selected fire scenarios associated with electrical cabinets. These updates required a focused-scope per review, which was conducted in June 2019 [Reference 40]. Two findings were identified during the focused-scope peer review, which were subsequently closed during an F&O independent assessment [Reference 41].

Four Fire PRA F&Os remain open and are dispositioned in Section A.3.1. All the Finding Level F&Os have been determined to not significantly affect the ILRT extension analysis.

### A.3.1 Disposition of Open Fire PRA Findings and Observations (F&Os)

| Finding Number | Supporting Requirement(s) | Capability Category (CC) | Description | Disposition for ILRT Extension |
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| HRA-C1-3 | HRA-C1<br><br>ASME/ANS RA-S-2007 (draft) | I/II/III<br><br>ANSI/ANS-58.23-2007 | HR-G1 was incorporated by reference. The approach to determining which HEPs are developed using a detailed analysis does not conform to the standard definition of significant for capability category II. Given the fact that the model is still in development, this is understandable. | *Supporting Requirements HRA-C1 and HR-G1 remained largely unchanged from ASME/ANS RA-S-2007 (draft) for which Finding HRA-C1-1 was initiated to ANSI/ANS-58.23-2007 for which the Capability Category I/II/III was determined. For ASME/ANS RA-Sa-2009, Supporting Requirement HRA-C1 was assigned Capability Categories of I, II, and III, but Support Requirement HR-G1 remained largely unchanged. Capability Category II was determined for HRA-C1.*<br><br>Tables 61 and 62 of HNP-F/PSA-0079, Rev. 3, list significant operator actions having a FV greater than 0.005 or RAW greater than 2, respectively. Section 7.1.3 of HNP-F/PSA-0075, Rev. 2, describes the selection of HFEs for detailed analysis. Based on established criteria (e.g., inadequate instrumentation or short time window), some significant HFEs were not selected for detailed analysis and were instead conservatively assumed to be failed or left at a screening value.<br><br>The impact to the ILRT extension analysis would be minimal. |
| HRA-C1-6 | HRA-C1<br><br>ASME/ANS RA-S-2007 (draft) | I/II/III<br><br>ANSI/ANS-58.23-2007 | HR-G6 was incorporated by reference. It is too early in the process for this supporting requirement to have been achieved satisfactorily, since only a few HFEs have been developed in detail. | *Supporting Requirements HRA-C1 and HR-G6 remained largely unchanged from ASME/ANS RA-S-2007 (draft) for which Finding HRA-C1-6 was initiated to ANSI/ANS-58.23-2007 for which the Capability Category I/II/III was determined. For ASME/ANS RA-Sa-* |

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| | | | | *2009, Supporting Requirement HRA-C1 was assigned Capability Categories of I, II, and III, but Support Requirement HR-G6 remained largely unchanged. Capability Category II was determined for HRA-C1.*<br><br>Plant-specific and scenario-specific influences on human performance were addressed by a well-defined and self-consistent process, as described in Section 7.1.3 of HNP-F/PSA-0075, Rev. 2. This ensured the results were logical and consistent with inputs and method of analysis.<br><br>There is no impact to the ILRT extension analysis. |
| FQ-E1-2 | FQ-E1<br><br>ASME/ANS RA-S-2007 (draft) | NOT MET<br><br>ANSI/ANS-58.23-2007 | The definition of significant contributor in the PRA standard includes the idea of summing, in rank order, the fire sequences and considering any in the top 95%, or any that individually contribute 1% or more, as significant. This determination has not been made for fire CDF or LERF. Harris does not appear to use the definition as provided in the PRA standard. | *Supporting Requirement FQ-E1 and the Supporting Requirements for HLR-QU-D and HLR-LE-F remained largely unchanged from ASME/ANS RA-S-2007 (draft), for which Finding FQ-E1-2 was initiated, to ANSI/ANS-58.23-2007, for which the NOT MET was determined, to ASME/ANS RA-Sa-2009.*<br><br>This SR continues to be NOT MET. This is a documentation-only issue and does not affect quantification of risk.<br><br>There is no impact to the ILRT extension analysis. |

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| FQ-F1-2 | FQ-F1<br><br>ASME/ANS RA-S-2007 (draft) | I/II/III<br><br>ASME/ANS RA-Sa-2009 | QU-F3 - There is currently no record of significant contributors to fire CDF. | *Supporting Requirement FQ-F1 and the Supporting Requirements for HLR-QU-F and HLR-LE-G remained largely unchanged from ASME/ANS RA-S-2007 (draft), for which Finding FQ-F1-2 was initiated, to ASME/ANS RA-Sa-2009, for which the Capability Category I/II/III was determined.*<br><br>Section 6.0 of HNP-F/PSA-0079, Rev. 3, documents the significant contributors to CDF, however accident sequences were not individually documented. This is a documentation-only issue.<br><br>There is no impact to the ILRT extension analysis. |