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March 27, 2017
GO2-17-009

10 CFR 50.90

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

Subject: **COLUMBIA GENERATING STATION, DOCKET NO. 50-397 LICENSE AMENDMENT REQUEST - REVISE TECHNICAL SPECIFICATION 5.5.12 FOR PERMANENT EXTENSION OF TYPE A TEST AND TYPE C LEAK RATE TEST FREQUENCIES**

Dear Sir or Madam:

Pursuant to 10 CFR 50.90, Energy Northwest hereby requests a license amendment to revise the Columbia Generating Station (Columbia) Technical Specification (TS) 5.5.12 for permanent extension of Type A and Type C Leak Rate Test Frequencies to 15 years (180 months) and 75 months respectively.

The proposed change has been evaluated in accordance with 10 CFR 50.91(a)(1) using criteria in 10 CFR 50.92(c) and it has been determined that this change involves no significant hazards considerations. The bases for these determinations are included in Enclosure 1 of this submittal.

The proposed TS markup pages are included as Enclosure 2 to this submittal. Clean pages of the proposed TS changes are included as Enclosure 3 of this submittal. Enclosure 4 contains the evaluation of risk significance of the proposed change.

This letter and its enclosures contain no regulatory commitments.

Approval of the proposed amendment is requested within one year of the date of the submittal. Once approved, the amendment shall be implemented within 60 days.

In accordance with 10 CFR 50.91, Energy Northwest is notifying the State of Washington of this amendment request by transmitting a copy of this letter and enclosures to the designated State Official.

If there are any questions or if additional information is needed, please contact Ms. L. L. Williams, Licensing Supervisor, at 509-377-8463.

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

Executed this 27th day of March, 2017.

Respectfully,

A. L. Javorik
Vice President, Engineering

Enclosures: As stated

cc: NRC RIV Regional Administrator
NRC NRR Project Manager
NRC Senior Resident Inspector/988C
CD Sonoda – BPA/1399 (email)
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WA Horin – Winston & Strawn

Evaluation of Proposed Technical Specification (TS) Change

1.0 SUMMARY DESCRIPTION

In accordance with 10 CFR 50.90, "Application for amendment of license, construction permit, or early site permit," Energy Northwest requests an amendment to Facility Operating License NPF-21 for Columbia Generating Station (Columbia). The proposed change revises TS 5.5.12, "Primary Containment Leakage Rate Testing Program" to allow the following:

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

- 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 ANSI/ANS 56.8-2002, "Containment System Leakage Testing Requirements" (Reference 14).

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

Specifically, the proposed change contained herein revises Columbia TS 5.5.12, by replacing the references to Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.163, "Performance-Based Containment Leak-Test Program," (Reference 1) and 10 CFR 50, Appendix J, Option B with a reference to NEI 94-01, Revision 3-A (Reference 2), and the conditions and limitations specified in NEI 94-01, Revision 2-A (Reference 3), as the documents used by Columbia to implement the performance-based leakage testing program in accordance with Option B of 10 CFR 50, Appendix J.

This license amendment request (LAR) also proposes administrative changes to the exceptions in TS 5.5.12. The exception regarding the performance of the next Columbia Type A test to be performed no later than July 20, 2009 will be deleted as this Type A test has already occurred. Additionally, the exception to compensate for flow meter inaccuracies in excess of those specified in ANSI/ANS 56.8-1994, “Containment System Leakage Testing Requirements” (Reference 13) will be deleted as new test equipment has been acquired with accuracies within the tolerances specified in ANSI/ANS 56.8-1994 and 2002.

2.0 DETAILED DESCRIPTION

Columbia TS 5.5.12, "Primary Containment Leakage Rate Testing Program," currently states, in part:

> "The Primary Containment Leakage Rate Testing Program shall establish 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 accordance with the guidelines contained in Regulatory Guide 1.163, “Performance-Based Containment Leak-Test Program,” dated September 1995, as modified by the following exceptions: The next Type A test performed after the July 20, 1994, Type A test shall be performed no later than July 20, 2009, and compensation for flow meter inaccuracies in excess of those specified in ANSI/ANS 56.8-1994 will be accomplished by increasing the actual instrument reading by the amount of the full scale inaccuracy when assessing the effect of local leak rates against the criteria established in Specification 5.5.12.a."

The proposed changes to Columbia TS 5.5.12 will replace the reference to RG 1.163 with a reference to NEI Topical Report NEI 94-01 Revisions 2-A and 3-A. This LAR also proposes administrative changes to two exceptions in TS 5.5.12. The exception regarding the performance of the next Columbia Type A test to be performed no later than July 20, 2009 will be deleted as this Type A test has already occurred.

Additionally, the exception to compensate for flow meter inaccuracies in excess of those specified in ANSI/ANS 56.8-1994 is being deleted as new test equipment has been acquired with accuracies within the tolerances specified in ANSI/ANS 56.8-1994 and 2002.

The proposed change will revise TS 5.5.12 to state, in part:

> "A program shall be established to implement the leakage rate testing of the primary containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR 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.”

Markup of TS 5.5.12 is provided in Enclosure 2. Enclosure 3 contains the clean pages. Enclosure 4 contains the plant specific risk assessment conducted to support this proposed change. This risk assessment followed the guidelines of NRC RG 1.174, Revision 2 (Reference 4). The risk assessment concluded that increasing the ILRT on a permanent basis to one-in-fifteen-year frequency is considered to represent a very small change in the Columbia risk profile.

3.0 TECHNICAL EVALUATION

3.1 Description of Primary Containment System

The reactor building consists of a dual barrier: the steel primary containment vessel and the reactor building (which provides secondary containment). The primary containment vessel contains the drywell, suppression chamber, structural floor separating the drywell from the suppression chamber, sacrificial shield wall (SSW), and reactor pedestal. The reactor building secondary containment encloses the biological shield wall, spent fuel storage pool, dryer-separator pool, and the reactor well pool.

The primary containment vessel is a freestanding steel pressure vessel. It utilizes the pressure suppression technique through the Mark II over-under configuration. It is designed to resist all normal operating loads, loads resulting from the postulated design basis accident (DBA) as well as those loads associated with the operating basis earthquake (OBE) and safe shutdown earthquake (SSE). The design also accounts for stresses induced by thermal expansion. The drywell floor, which divides the drywell and suppression chamber, is a reinforced-concrete slab supported by steel beams and concrete columns. The containment vessel is enclosed in a reinforced-concrete biological shield wall for shielding purposes and is separated from the reinforced concrete by an annulus of compressible isolation material, approximately 2 inches thick. The concrete wall thickness is governed by shielding requirements but also serves as a support from the reactor building floors. Shielding over the top of the drywell is provided by removable, segmented, reinforced-concrete shield plugs. The drywell is located directly above the wetwell. The drywell configuration is basically a frustum of a cone with a removable ellipsoidal top closure head. The suppression chamber (wetwell) is cylindrical with an ellipsoidal base. The primary containment vessel is anchored to the concrete mat foundation. The bottom of the suppression chamber is lined on the inside with reinforced concrete. The concrete mat foundation under the suppression chamber is a common foundation supporting the steel primary containment vessel, including all equipment and structures therein, and the reactor building of which the primary containment is a part.

The drywell floor serves as a pressure barrier between the drywell and suppression chamber. The top closure head of the drywell is bolted to a steel flange attached to the top of the containment vessel. The drywell houses the reactor vessel and its associated primary system. The primary function of the drywell is to contain the effects (i.e. mass and radiation) of a loss of coolant accident (LOCA), and to direct the steam released from a primary system pipe break into the suppression chamber pool to limit the total pressure rise during a LOCA.

The physical dimensions of the steel primary containment vessel are

a. The diameter of the cylindrical portion at the base of the cone is approximately 86 feet,

b. The diameter at the top of the cone is approximately 39.5 feet and then narrows to 32 feet to carry the removable head

c. Ellipsoidal bottom head with a ratio of 2:1 has an inside height of approximately 21.5 feet,

d. The removable ellipsoidal top closure head has an inside height of approximately 15.5 feet,

e. The drywell shell height is approximately 99 feet,

f. The suppression chamber shell height is approximately 72 feet, and

g. Overall shell height is approximately 171 feet.

The primary containment vessel shell plate thicknesses vary. Typical thicknesses are as follows:

a. Bottom ellipsoidal head: from 7/8 inch to 1.5 inches,
b. The suppression chamber cylinder: from 1-5/16 inches to 1.5 inches,
c. The drywell conical section: from 0.75 inch to 1.5 inches, and,
d. The removable top ellipsoidal head: 15/16 inch.

The primary containment vessel is reinforced with internal vertical and horizontal stiffeners to satisfy design requirements of the various loading combinations and conditions. Fully circumferential rings, attached to the inside face of the primary containment vessel are furnished at elevations 516 feet 6 inches and 542 feet 7.25 inches. The basic function of these rings is to support pipe whip loading protection framework and to adequately distribute pipe whip loading into the vessel.

The steel primary containment vessel, including all penetrations and welded attachments, is designed to act as a structural component within the reactor building. The primary containment is provided with two concentric circular skirts on the bottom ellipsoidal head integral with the vessel. The skirts are anchor bolted to the concrete foundation mat. The bottom ellipsoidal head and the upper portion of the skirts connected to the head are considered part of the containment pressure boundary. The skirts are backed up by concrete fill. The concrete fill and the concrete foundation mat are not part of the containment vessel.

A sand filled pocket area is provided at the surrounding exterior of the primary containment vessel near the base. The sand filled pocket area is used to collect any drainage between the primary containment vessel exterior and the biological shield wall. An embedded steel closure ring is installed on the top of the sand filled transition area.

3.1.1 Pipe Penetrations

Two general types of pipe penetrations are provided. The two types differ depending on whether the penetration is subject to a hot or cold operational environment. The cold penetrations pass through the steel primary containment vessel and are welded directly to it. The piping is normally welded directly to the penetration nozzles. The piping design includes the effects of thermal motion of the containment shell at the penetration connections.

The hot penetrations and multiple piping penetrations do not come in direct contact with the steel shell of the primary containment vessel. These penetrations pass through vessel shell nozzles, which are welded to the steel shell of the primary containment vessel and function as thermal sleeves. Containment closure is accomplished by means of closure plates or flued head fittings, welded to the penetration nozzle and the piping at a suitable distance outside the containment shell.

3.1.2 Electrical Penetrations

Containment electrical penetrations are designed to safely accommodate all of the electrical requirements within the containment boundary. These are functionally grouped into low voltage power and control cable penetrations assemblies, medium voltage power cable penetration assemblies, signal cable penetration assemblies and thermocouple cable penetration assemblies. The medium voltage power cable electrical penetrations are canister type assemblies sized to be inserted into the containment vessel penetration nozzles. All other electrical penetrations are a unitized header plate assembly attached to the outboard end of the containment vessel penetration nozzles.

3.1.3 Traversing In-Core Probe (TIP) Penetrations

Five TIP guide tubes pass from the reactor building to the drywell through the primary containment vessel. The penetrations are a Type 2 piping penetration modified with a welded neck flange attached outside the containment. This flange is itself modified with dual concentric o-ring grooves machined into the face, which retain elastomeric o-rings. To this is bolted a blank flange which has been drilled for both a between-o-ring test port and a central hole in which an instrument tubing “bulkhead union” fitting is retained. This single penetration point is sealed by seal welding between the bulkhead union and the blank flange. The TIP guide tubes are attached to both sides of their respective bulkhead unions by flare fittings.

3.1.4 Personnel Access Lock and the (Combined) Equipment Hatch and Control Rod Drive Removal Hatch

The drywell has one manually operated personnel air lock. This air lock consists of a cylindrical shell with two doors, one at each end of the shell. The cylindrical shell is approximately 8 feet 10.5 inches in diameter, which is sufficient to provide 6 feet 8-inch high by 3 feet 4-inch wide door openings above the floor. The minimum clear horizontal

distance not impaired by the door swing is 5 feet. Each door has double compressible seals with an air space between them so that each door may be individually tested. Each door is hinged and swings toward the drywell.

The air lock doors are designed so as to permit either door to be operated from inside the drywell, inside the air lock, or outside the drywell. In addition, the air lock doors are interlocked to ensure that at least one door is locked when the primary containment integrity is required. Signals and controls indicating the status of the doors are provided locally. The locking mechanisms are designed so that tight seals are maintained when the doors are subject to either the design internal or external pressure. A mechanical override is provided to permit temporary bypassing of the door interlock system to permit opening both doors under proper authorization. Quick acting equalizer valves are provided to equalize the pressure in the air lock when personnel enter or leave the primary containment vessel.

The drywell has one equipment removal hatch. The equipment hatch cover is dished and has steel stiffeners. The hatch cover is bolted to a flanged steel sleeve welded to the primary containment vessel shell such that the hatch cover can be removed and reinstalled from outside the drywell. The equipment hatch and cover is entirely supported by the steel containment vessel. Double compressible seals with an air space between them are used to permit leak testing at any time. The inside diameter of the equipment hatch is approximately 12 feet 6 inches which provides a minimum clearance above the floor at the hatch of 10 feet 1.5 inches high by 7 feet wide.

Included within the equipment hatch cover is a control rod drive (CRD) removal hatch with its hinged cover. This hatch is provided with leak-testable, double-gasketed seals. The inside diameter of this hatch is approximately 1 foot 11 inches in diameter which provides a minimum clearance of 11 inches high by 1 foot 4 inches wide at the hatch.

The personnel access lock and the equipment hatch extend radially outward across the annular gap of compressible isolation material and through the biological shield wall and are supported by the primary containment vessel only.

3.1.5 Pressure Suppression Chamber Access Hatch

Access to the pressure suppression chamber is provided at one location in the cylindrical well of the chamber approximately 7 feet 6 inches above the suppression pool operating water level. This access hatch is approximately 3 feet 5 inches in diameter, extends radially outward, is supported by the vessel and has a leak-testable, double-gasketed, bolted cover which is normally closed and is opened only when access to primary containment is required. The minimum clearance at the hatch is 2 feet 2.75 inches wide by 2 feet 5.5 inches high.

3.1.6 Access for Refueling Operations

The drywell containment head is removed during refueling operations. This head is held in place by bolts and is sealed with a double seal. It is bolted closed when primary

containment is required and is opened only when primary containment integrity is not required. The gasket seal is capable of limiting the leakage to below the design rate and is capable of being independently tested.

3.1.7 Vacuum Relief System

Three 24-inch reactor building-to-wetwell vacuum relief lines, each containing a 24-inch vacuum breaker valve and an automatic air-operated butterfly valve, are provided between the reactor building and the suppression chamber. These valves prevent excessive vacuum from developing in the primary containment vessel from such causes as inadvertent containment spray actuation.

Each butterfly valve is equipped with a spring-to-open, air-to-close operator which, during normal plant operation is maintained in a closed position by means of a control air supply through a three-way solenoid pilot valve.

In series with each butterfly valve is a single disk check valve. The disk is maintained in the closed position during normal operation by means of a spring-actuated lever arm and magnets embedded in the periphery of the disk. The magnetic and spring forces are overcome, and the disk opens when the pressure differential across the valve is within the range of 0.10 to 0.35 psi. The disk is fully open when the pressure difference is 0.5 psi.

Nine 24-inch wetwell-to-drywell vacuum relief valves attached to the downcomers in the suppression chamber are provided to return noncondensables from the wetwell to the drywell to prevent too large an upward pressure differential across the diaphragm floor after a LOCA.

Each wetwell-to-drywell vacuum relief valve assembly consists of two discs and seats which operate independently. The operation, controls and position indication for each disc is as described above for the single disc check valves. During normal plant operation the control air supply line to these valve assemblies is isolated except during surveillance testing. Also, residual pressure is vented from the line following vacuum relief valve testing to prevent inadvertent valve opening.

The vacuum breaker valves are sized to ensure that the following design conditions are not exceeded:

a. The drywell internal design pressure of 2.0 psi below reactor building pressure,
b. The suppression chamber internal design pressure of 2.0 psi below reactor building pressure, and
c. The upward design pressure difference across the diaphragm floor of 6.4 psi.

3.2 Plant Operational Performance

During power operation, the primary containment is inerted with nitrogen. The containment inerting system is used to purge the primary containment during plant start-

up, and to provide a supply of makeup nitrogen to maintain primary oxygen concentration within TS limits during power operation.

During power operation, instrument air system (i.e., nitrogen) leaks occur from pneumatically operated valves inside the containment, which gradually increase pressure inside the primary containment. Primary containment pressure is monitored and trended during plant operation, and is periodically vented in order to maintain containment pressure and atmosphere within an acceptable operating range. This cycling of the primary containment pressure during power operation amounts to a periodic integrated pressure test of the containment at a low differential pressure. Although this cycling does not challenge the structural and leak tight integrity of the primary containment system at post-accident pressure, it provides assurance that a gross containment leak that may develop during power operation will be detected.

This feature is a complement to visual inspection of the interior and exterior of the containment structure for those areas that may be inaccessible for visual examination.

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

Following issuance of NRC Bulletin 96-03, “Potential Plugging of Emergency Core Cooling Suction Strainers by Debris in Boiling Water Reactors,” the Columbia ECCS suction strainers were replaced to conform to the requirements of the bulletin. Strainer sizes were selected based on several criteria. The strainer beds had to be large enough to entrain post-LOCA wetwell debris without exceeding the maximum allowable head losses. The maximum head losses across the strainers were determined based on maintaining sufficient pressure in the pump suction lines to preclude cavitation under run-out conditions with the suppression pool water at 204.5° Fahrenheit (F).

Calculations demonstrating the acceptability of the strainers and the NPSH for all ECCS pumps were performed in accordance with RG 1.1, “Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps” (Reference 6). No credit is included in the calculations for wetwell air space pressure in excess of one atmosphere (14.696 pounds per square inch absolute (psia)) in the determination of available NPSH to the ECCS pumps. A wetwell air space pressure in excess of 14.696 psia will increase the available NPSH for the ECCS pumps. However, Energy Northwest is committed to the requirements of RG 1.1, which do not allow credit for wetwell airspace pressure.

3.4 Justification for the Technical Specification Change

3.4.1 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. The 10 CFR 50, Appendix J requirements also ensure that periodic surveillance 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 those 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 containment isolation valve leakage rates. Types B and C tests identify the vast majority of potential containment leakage paths. Type A tests identify the overall (integrated) containment leakage rate and serve to ensure continued leakage integrity of the containment structure by evaluating those structural parts of the containment not covered by Types B and C testing.

In 1995, 10 CFR 50, Appendix J, 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 7) with certain modifications and additions. Option B, in concert with RG 1.163 and NEI 94-01, Revision 0, allows licensees with a satisfactory ILRT performance history (i.e., two consecutive, successful Type A tests) to reduce the test frequency for the containment Type A (ILRT) test from three tests in 10 years to one test in 10 years. This relaxation was based on an NRC risk assessment contained in NUREG-1493, (Reference 8) and Electric Power Research Institute (EPRI) TR-104285 (Reference 9) both of which showed that the risk increase associated with extending the ILRT surveillance interval was very small. In addition to the 10-year ILRT interval, provisions for extending the test interval an additional 15 months were considered in the establishment of the intervals allowed by RG 1.163 and NEI 94-01, but that this 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 3), was issued. This document describes an acceptable approach for implementing the optional performance-based requirements of Option B to 10 CFR 50, Appendix J, subject to the limitations and conditions noted in Section 4.0 of the NRC Safety Evaluation Report (SER) on NEI 94-01. 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). It delineates a performance-based approach for determining Type A, Type B, and Type C containment leakage rate surveillance testing frequencies.

Justification for extending test intervals is based on the performance history and risk insights.

In 2012, NEI 94-01, Revision 3-A (Reference 2), was issued. This document describes an acceptable approach for implementing the optional performance-based requirements of Option B to 10 CFR 50, Appendix J and includes provisions for extending Type A ILRT intervals to up to 15 years. NEI 94-01 has been endorsed as an acceptable methodology for complying with the provisions of 10 CFR Part 50, Appendix J, Option B, by RG 1.163 and NRC SERs dated June 25, 2008 and June 8, 2012 (References 1, 10 and 11, respectively). The regulatory positions stated in RG 1.163 as modified by References 10 and 11 are incorporated in this document. It delineates a performance-based approach for determining Type A, Type B, and Type C containment leakage rate surveillance testing frequencies. Justification for extending test intervals is based on the performance history and risk insights. Extensions of Type B and Type C test intervals are allowed based upon completion of two consecutive periodic as-found tests where the results of each test are within a licensee's allowable administrative limits. Intervals may be increased from 30 months up to a maximum of 120 months for Type B tests (except for containment airlocks) and up to a maximum of 75 months for Type C tests. If a licensee considers extended test intervals of greater than 60 months for Type B or Type C tested components, the review should include the additional considerations of as-found tests, schedule and review as described in NEI 94-01, Revision 3-A, Section 11.3.2.

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 that states, in part:

> 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, in part, states that:

> "Consistent with standard scheduling practices for Technical Specifications Required Surveillances, intervals of up to 120 months for the recommended surveillance frequency for Type B testing and up to 75 months for Type C testing

given in this section may be extended by up to 25% of the test interval, not to exceed nine months.

Notes: For routine scheduling of tests at intervals over 60 months, refer to the additional requirements of Section 11.3.2.

Extensions of up to nine months (total maximum interval of 84 months for Type C tests) are permissible only for non-routine emergent conditions. This provision (nine-month extension) does not apply to valves that are restricted and/or limited to 30 month intervals in Section 10.2 (such as BWR Main Steam Isolation Valves (MSIVs)) or to valves held to the base interval (30 months) due to unsatisfactory LLRT performance."

The NRC has also provided the following concerning the extension of ILRT intervals to 15 years in NEI 94-01, Revision 3-A, NRC SER Section 4.0, Condition 2, which states, in part:

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.

3.4.2 Current Columbia Primary Containment Leakage Rate Testing Program Requirements

10 CFR 50, Appendix J was revised, effective October 26, 1995, to allow licensees to choose containment leakage testing under either Option A, "Prescriptive Requirements," or Option B, "Performance-Based Requirements." On May 8, 1996, the NRC approved TS Amendment 144 for Columbia (Reference 12) authorizing the implementation of 10 CFR 50, Appendix J, Option B for Types A, B and C tests.

Current TS 5.5.12 requires that a program be established to comply with the containment leakage rate testing requirements of 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B. The program is required to be in accordance with the guidelines contained in RG 1.163. RG 1.163 endorses, with certain exceptions, NEI 94-01, Revision 0 (Reference 7), 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 rather than using test intervals specified in ANSI/ANS 56.8-1994 (Reference 13). NEI 94-01, Section 11.0 refers to Section 9, which states that Type A testing shall be performed during a period of reactor shutdown at a frequency of at least once per ten years based on acceptable performance history. Acceptable performance history is defined as completion of two consecutive periodic Type A tests where the calculated performance leakage was less than $1.0L_a$ (where L_a is the

maximum allowable leakage rate at design pressure). Elapsed time between the first and last tests in a series of consecutive satisfactory tests used to determine performance shall be at least 24 months.

Adoption of the Option B performance-based containment leakage rate testing program altered the frequency of measuring primary containment leakage in Types A, B, and C tests but did not alter the basic method by which Appendix J leakage testing is performed. The test frequency is based on an evaluation of the "as found" leakage history to determine a frequency for leakage testing which provides assurance that leakage limits will not be exceeded. The allowed frequency for Type A testing as documented in NEI 94-01 is based, in part, upon a generic evaluation documented in NUREG-1493 (Reference 8). The evaluation documented in NUREG-1493 includes a study of the dependence of reactor accident risks on containment leak tightness for differing types of containment types, including a pressure suppression containment similar to the Columbia containment structure. NUREG-1493 concludes in Section 10.1.2 that reducing the frequency of Type A tests (ILRT) from the original three (3) tests per 10 years to one (1) test per 20 years was found to lead to an imperceptible increase in risk. The estimated increase in risk is very small because ILRTs identify only a few potential containment leakage paths that cannot be identified by Types B and C testing, and the leaks that have been found by Type A tests have been only marginally above existing requirements. Given the insensitivity of risk to containment leakage rate and the small fraction of leakage paths detected solely by Type A testing, NUREG-1493 concludes that increasing the interval between ILRTs is possible with minimal impact on public risk.

3.4.3 Columbia 10 CFR 50, Appendix J, Option B Licensing History

May 8, 1996

The NRC issued Amendment No. 144 which modified the TS for leak tests of CIVs. The amendment replaced the specified surveillance intervals for containment leak testing with new surveillance requirements to conduct containment leak testing according to a performance-based containment leak test program. In addition, this amendment originally granted an exemption, when using the flow makeup leak detection method, to use a flow meter accuracy of 4 percent rather than the 2 percent value specified in ANSI/ANS 56.8-1994 when performing local leak rate tests. This exception was requested because the flow meter accuracy was 4 percent. To compensate, the actual readings taken during tests were to be increased by the amount of the full scale inaccuracy when assessing the overall LLRT results against the TS limits. [Note: This exception is being deleted as part of this LAR as it is no longer necessary since new test equipment has been acquired with accuracies within the tolerances specified in ANSI/ANS 56.8-1994 and 2002 (Reference 12).]

April 12, 2005

The NRC issued Amendment No. 191, which revised TS 5.5.12, “Primary Containment Integrity.” This amendment allowed a one-time extension of the Columbia Appendix J,

Type A, Containment Integrated Leak Rate Test interval from the current 10-year interval to a proposed 15-year interval (Reference 15).

3.4.4 Integrated Leakage Rate Testing History

As noted previously, Columbia TS 5.5.12 currently requires Types A, B, and C testing in accordance with RG 1.163, which endorses the methodology for complying with Option B. Since the adoption of Option B, the performance leakage rates are calculated in accordance with NEI 94-01, Section 9.1.1 for Type A testing. Table 3.4.4-1 lists the past Periodic Type A ILRT results for CGS.

Table 3.4.4-1
Columbia Type A History

Test Date	Pa (psig) (Note 1)	Total Leakage wt % / day (Note 2)	Acceptance Limit wt % / day (Note 2)
2/16/1984 (Note 3)	34.7	0.2758%	0.50%
6/17/1987	34.7	0.3241%	0.50%
6/9/1991	34.7	0.297%	0.50%
7/20/1994	38.0 (Note 1)	0.302%	0.50%
6/14/2009	38.0 (Notes 1, 4)	0.3418%	0.50%

Note 1: The value of test pressure (Pa) for ILRT testing is currently 38.0 pounds per square inch gauge (psig), which is conservative, as the actual calculated accident pressure for Columbia is 37.4 psig. The calculated peak pressure increased from 34.7 to 37.4 psig due to Reactor Power Uprate in 1995. The 38.0 psig was used in the 1994 ILRT. The change in test pressure was made to preclude substantial retesting upon implementation of the power up-rate. The three previous ILRTs used a Pa of 34.7.

Note 2: Leakage rates are expressed in units of containment air weight percent per day (wt% / day) at Pa. Calculated results are expressed at a 95 percent confidence level plus leakage attributed to non-drained penetrations. Values prior to 1994 are considered the as-left leakage rate with the 1994 and 2009 performances representing the Performance Leak Rate defined in adoption of Options B. The maximum allowable primary containment leakage rate allowed by Option B during containment leak rate testing is 0.50% containment air weight per day (1.0 La).

Note 3: The February 16, 1984 performance was the pre-operational ILRT.

Note 4: The test pressure for the June 2009 ILRT was performed at 40.66 psig. The increase in test pressure is allowed by ANSI/ANS-56.8-1994, Section 3.2.11 since it does not exceed the Columbia containment design pressure of 45 psig.

For purposes of determining the extended ILRT interval at Columbia, the performance leakage rate was calculated for both the 1994 and 2009 ILRT performances. The 1994 ILRT was performed using the Mass Point method from ANSI/ANS 56.8-1987 as well as the total time method. The Total Time method results are presented in this LAR since it produced the most conservative value. During the 1994 ILRT, the as-left minimum pathway leakage rate (MNPLR) 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 was 0.0114 wt.%/day. The pathways which contributed to the MNPLR are as follows with the post-test leak rate correction expressed in standard cubic centimeters (sccm):

Table 3.4.4-2
1994 ILRT Pretest Leakage Penalties for Non-Vented or Isolated Penetrations

Penetration Number	Reason for Penalty	Post-Test Leak Rate Correction (SCCM)
5	In Service	0
11A	Not Drained	17
11B	Not Drained	6
13	Not Drained	0
14	Not Drained	4
17A	Not Drained	44
17B	Not Drained	1
25A	Not Drained	115
25B	Not Drained	31
26	Not Drained	141
43A	Not Drained	1
43B	Not Drained	6
46	In Service	280
47	Not Drained	750
48	Not Drained	210
49	Not Drained	409
63	Not Drained	135
65	Not Drained	9
77Aa	Not Drained	30
77Ac	Not Drained	106
77Ad	Not Drained	0
82d	Not Drained	1
88	Not Drained	2

Table 3.4.4-2 1994 ILRT Pretest Leakage Penalties for Non-Vented or Isolated Penetrations		
Penetration Number	**Reason for Penalty**	**Post-Test Leak Rate Correction (SCCM)**
117	Not Drained	356
118	Not Drained	35
		Total Correction 2689 SCCM
		Total Correction 0.0114 wt.%/day

The 95% upper confidence limit (UCL) for the 1994 ILRT was 0.302 wt.%/day which includes the summation of MNPLR additions of 0.0114 wt.%/day for the Type B and C pathways in Table 3.4.4-2 and provides the performance leakage rate. The performance leakage rate for the 1994 ILRT (0.302 wt.%/day) is well below the acceptance limit of less than 1.0La (0.50 %wt./day).

The ANSI/ANS 56.8-1987 version of the standard requires the ILRT to be performed at a pressure equal to or greater than P_{ac} (accident pressure) to start, but shall not exceed the containment design pressure and shall not be permitted to fall more than 1 psi below P_{ac} for the duration of the test. Design pressure for the Columbia containment is 45 psig. Calculated Peak LOCA pressure for Columbia was 38.0 psig. Test pressure at the start of stabilization for the 1994 ILRT was 38.7 psig and remained above 38.0 psig during the test, which met the ILRT test pressure requirements of ANSI/ANS 56.8-1987.

The 2009 ILRT was performed using the Mass Point method from ANSI/ANS 56.8-1994. During the 2009 ILRT, the MNPLR for all Type B and Type C pathways that were in service, isolated or not lined up in their test position prior to performing the ILRT was 0.008 %wt./day. The pathways which contributed to the MNPLR are as follows:

Table 3.4.4-3 2009 ILRT Pretest Leakage Penalties for Non-Vented or Isolated Penetrations		
Penetration Number	**Containment Isolation Valves**	**As-Left MNPLR (SCFH)**
X-4	RCIC-V-68, RCIC-V-40	0.37
X-5	RCC-V-5, RCC-V-104	1
X-13	SLC-V-7, SLC-V-4A, SLC-V-4B	0.002
X-14	RWCU-V-1, RWCU-V-4	0.01
X-17A	RFW-V-10A, RFW-V-32A, RFW-V-65A, RFW-V-65B, RFW-V-32B	0.055
X-17B	RFW-V-10B, RFW-V-32B	0

Table 3.4.4-3 2009 ILRT Pretest Leakage Penalties for Non-Vented or Isolated Penetrations		
Penetration Number	**Containment Isolation Valves**	**As-Left MNPLR (SCFH)**
X-21	RCIC-V-63, RCIC-V-64, RCIC-V-8, RCIC-V-76	0.13
X-22	MS-V-16, MS-V-19	0.002
X-23	EDR-V-19, EDR-V-20	0.28
X-24	FDR-V-3, FDR-V-4	0.01
X-25A	RHR-V-27A	0.07
X-25B	RHR-V-27B	0.04
X-27	TIP-V-1, TIP-V-2, TIP-V-3, TIP-V-4, TIP-V-5, TIP-V-6, TIP-V-15	0.25
X-29a/c	PI-VX-256, PI-VX-257	0.006
X-43A	RRC-V-13A, RRC-V-16A	0.002
X-43B	RRC-V-13B, RRC-V-16B	0.004
X-46	RRC-V-40, RRC-V-21, RRC-V-219	0.8
X-54Aa	RCIC-V-184, RCIC-V-740	0.002
X-56	CIA-V-20, CIA-V-21	0
X-69c	PI-V-X69C, PI-VX-221	0.002
X-72f	PI-VX-253, PI-V-X72F/1	0.008
X-73e	PI-VX-259, PI-V-X73E/1	0.002
X-73f	PSR-V-X73/1, PSR-V-X73/2	0.12
X-77Aa	RRC-V-19, RRC-V-20	0.1
X-77Ac	PSR-V-X-77A/1, PSR-V-X77A/2	0.002
X-77Ad	PSR-V-X77A/3, PSR-V-X77A/4	0.004
X-78d	LPCS-V-66, LPCS-V-67	0.004
X-78e	HPCS-V-65, HPCS-V-68	0.02
X-80b	PSR-V-X80/1, PSR-V-X80/2	0.29
X-82d	PSR-V-X82/1, PSR-V-X82/2	0
X-82f	PSR-V-X82/7, PSR-V-X82/8	0.07
X-83a	PSR-V-X83/1, PSR-V-X83/2	0.37
X-84f	PSR-V-X84/1, PSR-V-X84/2	0.03

Table 3.4.4-3 2009 ILRT Pretest Leakage Penalties for Non-Vented or Isolated Penetrations		
Penetration Number	**Containment Isolation Valves**	**As-Left MNPLR (SCFH)**
X-85a/c	PI-VX-250, PI-VX-251	0.01
X-88	PSR-V-X88/1, PSR-V-X88/2	0
X-89B	CIA-V-30A, CIA-V-31A	0.04
X-91	CIA-V-30B, CIA-V-31B	0.06
		Total As-Left MNPLR 4.165 SCFH
		Total As-Left MNPLR 0.008 wt.%/day

The 95% UCL for the 2009 ILRT was 0.3418 wt.%/day which includes the summation of the MNPLR additions of 0.008 %wt./day for the Type B and C pathways in Table 3.4.4-3 and provides the performance leakage rate. The performance leakage rate for the 2009 ILRT (0.3418 wt.%/day) is well below the acceptance limit of less than 1.0La (0.50 %wt./day).

The ANSI/ANS 56.8-1987 of the ANSI standard requires the ILRT to be performed at a test pressure not less than 0.96 P_{ac} nor exceed P_a. For those plants with a P_{ac} of 25 psig or less, P_{ac} minus 1 psig shall be the minimum test pressure for the duration of the ILRT. Design pressure for the Columbia containment is 45 psig. Calculated Peak LOCA pressure for Columbia is 38.0 psig. The test pressure during the 2009 ILRT was 40.66 psig, which met the ILRT test pressure requirements of ANSI/ANS 56.8-1994.

The results of the last two Type A ILRTs for Columbia were less than the maximum allowable containment leakage rate of 0.50 wt % / day. As a result, since both tests were successful, Columbia has been placed on an extended ILRT frequency. The current ILRT interval frequency for Columbia is 10 years.

3.5 Plant Specific Confirmatory Analysis

3.5.1 Methodology

A plant specific confirmatory analysis was performed to provide a risk assessment of extending the currently allowed containment Type A ILRT to a permanent interval of fifteen years. The risk assessment follows the guidelines from:

1. NEI 94-01, Revision 3-A (Reference 2), the methodology used in EPRI TR-104285 (Reference 9).
2. The NEI document Interim Guidance for Performing Risk Impact Assessments In Support of One-Time Extensions for Containment Integrated Leakage Rate Test Surveillance Intervals (Reference 29).

3. The NRC regulatory guidance on the use of Probabilistic Risk Assessment (PRA) as stated in Regulatory Guide 1.200 (Reference 5) as applied to ILRT interval extensions.
4. Risk insights in support of a request for a change of the plant's licensing basis as outlined in RG 1.174 (Reference 4).
5. The methodology used for Calvert Cliffs to estimate the likelihood and risk implications of corrosion-induced leakage of steel liners going undetected during extended test interval (Reference 30).
6. The methodology used in EPRI 1009325, Revision 2-A (Reference 18).

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

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 7) states that NUREG-1493, "Performance-Based Containment Leak Test Program," September 1995 (Reference 8), provides the technical basis to support rulemaking to revise leakage rate testing requirements contained in Option B to Appendix J. The basis consisted of qualitative and quantitative assessments of the risk impact (in terms of increased public dose) associated with a range of extended leakage rate test intervals. To supplement the NRC's rulemaking basis, NEI undertook a similar study. The results of that study are documented in Electric Power Research Institute (EPRI) Research Project Report TR-104285, "Risk Impact Assessment of Revised Containment Leak Rate Testing Intervals." The NRC report on performance-based leak testing, NUREG-1493, analyzed the effects of containment leakage on the health and safety of the public and the benefits realized from the containment leak rate testing. In that analysis, it was determined for a representative PWR plant (i.e., Surry), that containment isolation failures contribute less than 0.1 percent 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 Columbia.

The Guidance provided in Appendix H of EPRI Report No. 1009325, Revision 2-A, Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals (Reference 18) for performing risk impact assessments in support of ILRT extensions builds on the EPRI Risk Assessment methodology, EPRI TR-104285. This methodology is followed to determine the appropriate risk information for use in evaluating the impact of the proposed ILRT changes.

It should be noted that containment leak-tight integrity is also verified through the 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 refueling 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 (and will continue prescribed intervals).

The following ground rules and assumptions are used in the analysis (it should be noted that many of these ground rules were cited explicitly in Reference 18):

1. The technical adequacy of the Columbia PRA is consistent with the requirements of RG 1.200 as is relevant to this ILRT interval extension.
2. The Columbia Level 1 and Level 2 internal events Probabilistic Safety Assessment (PSA) models provide representative results.
3. It is appropriate to use the Columbia internal events PRA model as a gauge to effectively describe the risk change attributable to ILRT extension. It is reasonable to assume that the impact from the ILRT extension (with respect to percent increases in population dose) will not substantially differ if fire and seismic events were to be included in the calculations.
4. Dose results for the containment failures modeled in the PRA can be characterized by information provided for the Severe Accident Management Alternative (SAMA) analysis in the Columbia WinMACCS Assessment of Severe Accident Consequences (Reference 42) and also in the SAMA portion of the Columbia License Renewal Application (Reference 26).
5. Accident classes describing radionuclide release end states are defined consistent with EPRI methodology (Reference 9) and are summarized in Section 4.2 of Enclosure 4 of this submittal.
6. The representative containment leakage for Class 1 sequences is 1.0 La. Class 3 accounts for increased leakage due to Type A inspection failures.
7. The representative containment leakage for Class 3a sequences is 10La based on the previously approved methodology performed for Indian Point Unit 3 (References 43 and 44).
8. The representative containment leakage for Class 3b sequences is 100La based on the guidance provided in EPRI Report No. 1009325, Revision 2.
9. The Class 3b can be very conservatively categorized as large early release frequency (LERF) based on the previously approved methodology (References 43 and 44).
10. The impact on population doses from containment bypass scenarios is not altered by the proposed ILRT extension, but is accounted for in the EPRI methodology as a separate entry for comparison purposes. Since the

containment bypass contribution to population dose is fixed, no changes on the conclusions from this analysis will result from this separate categorization.

11. The reduction in ILRT frequency does not impact the reliability of containment isolation valves to close in response to a containment isolation signal.
12. All quantifications for this analysis were performed at a 2.0E-12/yr. truncation limit.
13. The “with maintenance” Columbia Model of Record (MOR), References 45 and 46, was used for all quantative results.
14. The random containment large isolation failure probability for large valves (8.36E-4) is assumed to equal the Columbia Bayesian-updated probability for a safety-related motor-operated valve failing to close on demand found in Reference 47 (Bayesian Update of Columbia PSA Data, Revision 4). The assumption is consistent with the wording in Section 4.3 of Reference 18, which states, ”Class 2 sequences: This group consists of all core damage accident progression bins for which a pre-existing leakage due to failure to isolate the containment occurs. These sequences are dominated by failure to close of large (> 2 inches [5.1 cm] in diameter) containment isolation valves.

In the Safety Evaluation (SE) issued by the NRC letter dated June 25, 2008 (Reference 10), the NRC concluded that the methodology in EPRI TR-1009325, Revision 2, was acceptable for referencing by licensees proposing to amend their TS to extend the ILRT surveillance interval to 15 years, subject to the limitations and conditions noted in Section 4.0 of the SE. Table 3.5.1-1 addresses each of the four limitations and conditions for the use of EPRI 1009325, Revision 2.

Table 3.5.1-1
EPRI Report No. 1009325 Revision 2 Limitations and Conditions

Limitation/Condition (From Section 4.2 of SE)	Energy Northwest 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."	Columbia PRA technical adequacy is addressed in Section 3.5.2 of this LAR and Enclosure 4, “Evaluation of Risk Significance of Permanent ILRT Extension for Columbia Generating Station,” Appendix A, PRA Model Technical Adequacy.

Table 3.5.1-1 EPRI Report No. 1009325 Revision 2 Limitations and Conditions	
Limitation/Condition (From Section 4.2 of SE)	**Energy Northwest Response**
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."	RG 1.174 provides guidance for determining the risk impact of plant-specific changes to the licensing basis. RG 1.174 defines very small changes in risk as resulting in increases of core damage frequency (CDF) below 10^{-6}/year and increases in LERF below 10^{-7}/year. Since the ILRT does not impact CDF, the relevant criterion is LERF. The increase in LERF resulting from a permanent change in the Type A ILRT test interval from three in ten years to once in fifteen years is very conservatively estimated as 3.07E-08/year using the EPRI guidance as written. As such, the estimated change in LERF is determined to be “very small” using the acceptance guidelines of RG 1.174. The ΔLERF values associated with the ILRT interval change to 15 years for each of the hazard groups examined (internal events, fire, or seismic) is less than 1.0E-7/yr; these increases would, therefore, be classified as being “very small” per Regulatory Guide 1.174. If one sums the internal events, fire, and seismic hazard group values, one sees that the increase in LERF is 1.10E-7/yr; per RG 1.174 this is a “small change” (increase) in LERF, given that the baseline LERF value of 2.83E-6/yr for this bounding case is between 1E-6/yr and 1E-5/yr. The large margin between summed LERF value and the threshold provides assurance that the small risk increase associated with this application is acceptable when one accounts for the significant level of uncertainty associated with the fire and seismic PRA model results.

Table 3.5.1-1 EPRI Report No. 1009325 Revision 2 Limitations and Conditions	
Limitation/Condition (From Section 4.2 of SE)	**Energy Northwest Response**
2.b "Specifically, a small increase in population dose should be defined as an increase in population dose of less than or equal to either 1.0 person-rem per year or 1% of the total population dose, whichever is less restrictive."	The change in Type A test frequency to once-per-fifteen-years, measured as an increase to the total integrated plant risk for those accident sequences influenced by Type A testing, is 2.77E-4 person-rem/year (a 0.00761% increase). EPRI Report No. 1009325, Revision 2-A states that a very small population dose is defined as an increase of ≤1.0 person-rem per year or ≤ 1% of the total population dose, whichever is less restrictive for the risk impact assessment of the extended ILRT intervals. Moreover, the risk impact when compared to other severe accident risks is negligible.
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 frequency from the three in ten year interval to once in fifteen year interval is 0.51%. EPRI Report No. 1009325, Revision 2-A states that increases in CCFP of less than or equal to 1.5 percentage points are very small. Therefore this increase is judged to be very small.
3. "The methodology in EPRI Report No. 1009325, Revision 2, is acceptable except for the calculation of the increase in expected population dose (per year of reactor operation). In order to make the methodology acceptable, the average leak rate accident case (accident case 3b) used by the licensees shall be 100 L_a instead of 35 L_a."	The representative containment leakage for Class 3b sequences is 100La based on the guidance provided in EPRI Report No. 1009325, Revision 2. It should be noted that this is more conservative than the earlier previous industry Type A test interval extension requests, which utilized 35 La for the Class 3B sequences.

Table 3.5.1-1 EPRI Report No. 1009325 Revision 2 Limitations and Conditions	
Limitation/Condition (From Section 4.2 of SE)	**Energy Northwest Response**
4. "A [license amendment request] LAR is required in instances where containment over-pressure is relied upon for ECCS performance."	No credit is included in the calculations for wetwell air space pressure in excess of one atmosphere (14.696 psia) in the determination of available NPSH to the ECCS pumps. A wetwell air space pressure in excess of 14.696 psia will increase the available NPSH for the ECCS pumps. However, Columbia is committed to the requirements of RG 1.1, which do not allow credit for wetwell airspace pressure. Reference Section 3.3 of this Enclosure for details.

3.5.2 Technical Adequacy of the PRA

3.5.2.1 Demonstrate the Technical Adequacy of the PRA

The guidance provided in RG 1.200, Revision 2, Section 4.2, “License Submittal Documentation,” indicates that the following items be addressed in documentation submitted to the NRC to demonstrate the technical adequacy of the PRA:

- Identify plant changes (design or operational practices) that have been incorporated at the site, but are not yet in the PRA model and justify why the change does not impact the PRA results used to support the application.

- Document peer review findings and observations (F&Os) that are applicable to the parts of the PRA required for the application, and for those that have not yet been addressed justify why the significant contributors would not be impacted.

- Document that the parts of the PRA used in the decision are consistent with applicable standards endorsed by the RG. Provide justification to show that where specific requirements in the standard are not met, it will not unduly impact the results.

- Identify key assumptions and approximations relevant to the results used in the decision-making process.

3.5.2.2 Technical Adequacy of the PRA Model

The Columbia Model Version 7.2.1 model update is the most recent evaluation of the risk profile at Columbia for internal event (including internal flooding) challenges. The Columbia PRA modeling is highly detailed, including a wide variety of initiating events, modeled systems, operator actions, and common cause events. The PRA model quantification process used for the Columbia PRA is based on the event tree/fault tree methodology.

It was concluded that the Columbia PRA quality is sufficient to support TSTF-425 (Reference 36, 37 and 38); Section 3.5.2.5 of this submittal contains more information on the applicability of the TSTF-425 assessment of PRA quality to the ILRT submittal.

Columbia employs a multi-faceted approach for establishing and maintaining the technical adequacy and plant fidelity of the PRA model. This approach includes both a proceduralized PRA maintenance and update process and the use of independent peer reviews. The following information describes this approach as it applies to the Columbia PRA.

3.5.2.3 PRA Maintenance and Update

The Columbia risk management process ensures that the PRA model remains an accurate reflection of the as-built and as-operated plant. This process is defined in the Columbia PRA model maintenance and configuration control program in accordance with the governing procedure, SYS-4-34. The procedure delineates the responsibilities and guidelines for updating the full power internal events PRA model. It also defines the process for implementing regularly scheduled reviews and interim PRA model updates, for tracking issues identified as potentially affecting the PRA models (e.g., due to changes in the plant, errors or limitations identified in the model, industry operating experience), and for controlling the model and associated computer files. To ensure the current PRA model remains an accurate reflection of the as-built, as-operated plants, the following activities are routinely performed:

- Design changes and procedure changes are reviewed for their impact on the PRA model.
- Maintenance unavailabilities are captured, and their impact on CDF is trended.
- Plant specific initiating event frequencies, failure rates, and maintenance unavailabilities are updated periodically.

In addition to these activities Columbia risk management procedures provide the guidance for particular risk management, PRA quality, and maintenance activities. This guidance includes:

- Documentation of the PRA model, PRA products and bases documents.
- The approach for controlling electronic storage of risk management products including PRA update information, PRA models, and PRA applications.

- Guidelines for updating the full power, internal events PRA models for Columbia.
- Guidance for use of quantitative and qualitative risk models in support of the Work Control Process Program for risk evaluations for maintenance tasks (corrective maintenance, preventative maintenance, minor maintenance, surveillance tests and modifications) on systems, structures, and components (SSCs) within the scope of the Maintenance Rule (10 CFR 50.65(a)(4)).

3.5.2.4 Plant Changes Not Yet Incorporated into the PRA Model

A review of plant modifications and procedure changes was performed. Plant emergency operating procedures (EOPs) have been modified to implement early containment vent if primary containment pressure reduction is required to maintain adequate core cooling during an extended loss of AC power. The reactor core isolation cooling (RCIC) backpressure trip signal is overridden; RCIC can maintain operation while drawing suction from the Condensate Storage Tank (CST) or from the suppression pool for suppression pool temperatures up to 240 degrees F. These procedural features significantly improve the operational availability of RCIC. This procedural enhancement has not been credited in the applicable SBO accident sequences, and a self-assessment observation has been made to address this enhancement in a future PRA update.

There are several modifications with PRA impact that are scheduled to be implemented in the upcoming refueling outage. The evaluation of these planned plant changes is presented in Table A-1 of Enclosure 4 of this submittal. One change would improve the risk profile as implemented and two would have minimal quantitative impact if implemented. Based upon this analysis, it can be concluded that the current PRA model is representative (with a conservative bias) with respect to the current plant configuration and also with respect to the ILRT extension request calculations.

3.5.2.5 PRA Technical Adequacy for the Current Model of Record

The Columbia PRA model of record is Revision 7.2.1. Revision 7.2.1 is a minor model update based upon Revision 7.2. The Columbia PRA meets Capability Category II of Addendum A of the ASME ANS Standard (Reference 31), as clarified by RG 1.200, Revision 2 (Reference 5). All ASME Standard Supporting Requirements currently meet or exceed the Capability Category II.

The following is a brief history of the Columbia PRA model and associated peer reviews, as well as a summary of the modeling modifications that were performed to create Revision 7.2 and Revision 7.2.1.

1. In 2004 the Columbia PRA received a peer review against the Capability Category II requirements of Addendum A of the 2002 ASME PRA Standard. The Rev. 7.1 PRA resolved all of the 2004 peer review F&Os with the exception of one D-level F&O, HR-D7-1, which the Revision 7.2 PRA has now resolved. The results of this peer review were superseded by the 2009 peer review (discussed in Item 2 below).

2. In 2009, the Columbia PRA received a peer review against the ASME / ANS PRA Standard, as clarified by RG 1.200, Revision 2. All F&O Findings from the 2009 Peer Review have been resolved. Table A-2 of Enclosure 4 of this submittal summarizes the resolution of the findings from the 2009 peer review associated with supporting requirements that did not meet or exceed Capability Category II.

3. The Columbia plant design has been reviewed for permanent plant changes, such as design or operational practices. For the Revision 7.2 PRA update, those changes that were found to have an impact on the PRA were incorporated into the baseline PRA model, as applicable:

    a. The Group 1 nuclear steam supply shutoff system (MSIV) actuation set point changed from Reactor Level 2 to Level 1. This design change impacts the plant transient response and PRA in the following manner:

        - Power conversion system (PCS) availability – Following a plant transient and loss of reactor feedwater, the high pressure core spray (HPCS) and reactor core isolation cooling (RCIC) systems will receive a signal to start when an “A” actuation signal is generated when reactor level reaches Level 2. If HPCS or RCIC start, reactor Level 1 will not be reached and the MSIVs will initially remain open, which supports decay heat removal through the PCS. However, an "A" actuation signal trips non-essential power supplies, including power to the main steam tunnel coolers. A heat-up of the main steam tunnel leads to MSIV closure and loss of PCS. Therefore, this plant design change produced no material change in the availability of PCS from a PRA perspective and no change in the PRA results.
        - Plant operator response to anticipated transient without scram (ATWS) – The change of the MSIV actuation set point to Level 1 potentially improves the timing for operators to bypass the MSIV low level interlock. The reactor pressure vessel (RPV) control (ATWS) response is directed from Emergency Operating Procedure (EOP) 5.1.2 “RPV Control (ATWS)”. One of the actions is to reduce RPV water level to minimize power production. This initially occurs to below the feedwater sparger which generally would not lead to MSIV closure. If the containment and RPV conditions cannot be controlled, RPV level must be lowered further. The MSIV interlock on low RPV water level is directed to be bypassed in parallel with tasks associated with lowering RPV water level. Since bypass of the MSIV interlock is one of the immediate control room activities that are undertaken to cope with the plant challenges, no significant change in the human error probability is judged to apply. Therefore, no change was made in the error probability for human failure event MS-H-ATWBYP-H3XX, “Operator fails to bypass MSIV Interlock.”

b. Containment vent without alternating current (AC) and direct current (DC) power available – A procedure has been implemented to vent containment without AC and DC power available. Operators locally manipulate valves to vent containment from the drywell or wetwell. This operational enhancement has been added to the Columbia PRA Revision 7.2.

4. In PRA minor model release Revision 7.2.1, selected dependent HEP values were modified for use in the non-LERF Level 2 release term quantification and separate recovery files were constituted to implement these recoveries. The revisions associated with this model release had no impact on the CDF or LERF modeling or quantitative solutions; therefore, the release of this model version had no impact on the assessed technical adequacy of the PRA with respect to the ASME Standard.

5. The description of the PRA technical adequacy for this ILRT application (including resolutions to the F&Os presented in Table A-2 of Enclosure 4 of this submittal) is consistent with that presented in the TSTF-425 (Risk Informed Surveillance Interval) risk assessment incorporated into the TSTF-425 LAR. The TSTF-425 LAR for Columbia was approved by the NRC on November 3, 2016 (References 36, 37 and 38).

3.5.2.6 Potential Impact from External Events

Evaluation of high winds, external floods, volcanic eruption and other external events in the individual plant examination of external events (IPEEE) per NRC generic letter (GL) 88-20 were submitted to and reviewed by the NRC. The Staff Evaluation Report concluded that the Columbia IPEEE was capable of identifying the most likely severe accidents and severe accident vulnerabilities and the IPEEE met the intent of Supplement 4 to GL 88-20. The IPEEE determined that the recurrence frequency for the maximum tornado wind speed is approximately 1E-07/yr and, as such, maximum wind speed was eliminated as a plant hazard per the Standard Review Plan. Other external events (e.g., external fire, external floods, high winds, volcanic eruption etc.) were considered to be insignificant contributors to severe accidents. The proposed changes should have a negligible effect on the risk profiles from other external events.

The current Columbia internal fire and seismic PRA models were created based upon analysis performed in the IPEEE, with periodic updates to reflect the as-built, as-operated plant. Since the current seismic and internal fire PRA models at Columbia were not developed using methods that are consistent with the ASME Standard supporting requirements, these models are not deemed to be of sufficient quality to provide numerical estimates of fire and seismic event risk of equal quality to the internal events model; therefore, the methodology used to estimate the risk associated with internal events presented in Sections 5.1 through 5.4 of Enclosure 4 of this submittal is not replicated for these hazards. However, results from the current CGS internal fire and seismic model results are presented to provide qualitative insights into the risk

associated with these hazards, as well as to provide an order of magnitude estimate for the increase in LERF attributable to these hazards.

RG 1.174 provides NRC recommendations for using risk information in support of applications requesting changes to the license basis of the plant. The Regulatory Guide 1.174 acceptance guidelines are used here to assess the ILRT interval extension. Those acceptance guidelines are presented in Figure 5-1 of Enclosure 4 of this submittal (which is excerpted from RG 1.174). Table 5-19 of Enclosure 4 of this submittal summarizes the results for the external event LERF increase analysis performed at Columbia.

As can be seen from Table 5-19 of Enclosure 4 of this submittal, none of the ΔLERF values in the internal events, fire, or seismic hazard groups exceeds 1.0E-07/yr; these increases would, therefore, be classified as being "very small" per Figure 5-1 of Enclosure 4 of this submittal. If one sums the internal events, fire, and seismic hazard group values, one sees that the increase in LERF is 1.10E-7/yr; per Regulatory Guide 1.174 (and Figure 5-1 of Enclosure 4 of this submittal), this is a "small change" (increase) in LERF, given that the baseline LERF value of 2.83E-6/yr for this bounding case is between 1E-6/yr and 1E-5/yr. The large margin between summed LERF value and the threshold provides assurance that the small risk increase associated with this application is acceptable when one accounts for the significant level of uncertainty associated with the fire and seismic PRA model results.

3.5.3 Summary of Plant-Specific Risk Assessment Results

Based on the quantitative results and the sensitivity calculations presented in Sections 5 and 7 of Enclosure 4 of this submittal, the following conclusions regarding the assessment of the plant risk are associated with extending the Type A ILRT test frequency to fifteen years:

1. Reg. Guide 1.174 (Reference 4) provides guidance for determining the risk impact of plant-specific changes to the licensing basis. Reg. Guide 1.174 defines very small changes in risk as resulting in increases of CDF below 10^{-6}/yr and increases in LERF below 10^{-7}/yr. Since the ILRT does not impact CDF, the relevant criterion is LERF. The increase in LERF resulting from a permanent change in the Type A ILRT test interval from three in ten years to one in fifteen years is very conservatively estimated as 3.07E-08/yr using the EPRI guidance as written,. As such, the estimated change in LERF is determined to be "very small" using the acceptance guidelines of Reg. Guide 1.174.

2. The Δ LERF values associated with the ILRT interval change to 15 years for each of the hazard groups examined (internal events, fire, or seismic) is less than 1.0E-7/yr; these increases would, therefore, be classified as being "very small" per Regulatory Guide 1.174. If one sums the internal events, fire, and seismic hazard group values, one sees that the increase in LERF is 1.10E-7/yr; per Regulatory Guide 1.174 this is a "small change" (increase) in LERF, given that the baseline LERF value of 2.83E-6/yr for this bounding case is between 1E-6/yr

and 1E-5/yr. The large margin between summed LERF value and the threshold provides assurance that the small risk increase associated with this application is acceptable when one accounts for the significant level of uncertainty associated with the fire and seismic PRA model results.

3. 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, is 2.77E-4 person-rem/yr (a 0.00761% increase). EPRI Report No. 1009325, Revision 2-A states that a very small population dose is defined as an increase of ≤ 1.0 person-rem per year or ≤1% of the total population dose, whichever is less restrictive for the risk impact assessment of the extended ILRT intervals. Moreover, the risk impact when compared to other severe accident risks is negligible.

4. The increase in the conditional containment failure frequency from the three in ten year interval to one in fifteen year interval is 0.51%. EPRI Report No. 1009325, Revision 2-A states that increases in CCFP of less than or equal to 1.5 percentage points are very small. Therefore this increase judged to be very small.

5. Since containment overpressure is not required in the Columbia design basis or the Columbia PRA model to support ECCS performance to mitigate accidents at Columbia, the effect of the ILRT extension on containment overpressure need not be addressed.

Therefore, based upon the above factors, the overall risk of increasing the ILRT interval to once per 15 years is considered to be non-significant, since it represents a small change to the Columbia risk profile.

3.6 Non-Risk Based Assessment

3.6.1 Columbia Service Level 1 Coatings Program

The Columbia Service Level 1 Coatings Program is a series of systematic and planned activities designed to ensure that safety related coatings perform their intended function. The program monitors, through inspection, Service Level 1 coatings within containment and Service Level 3 coatings. The program is also designed to ensure the DBA analysis limits will not be exceeded for the ECCS suction strainers.

A containment inspection, which includes both the drywell and suppression pool, is performed by a qualified coatings inspector during each refueling outage. Routinely, 50 percent of the accessible suppression pool coatings below the water line are examined each refueling cycle with a total of 100 percent being examined every two refueling cycles (4 years). The inspection monitors the drywell and suppression pool coatings for evidence of blistering, cracking, flaking, peeling, delamination or rusting. The Coatings Engineer evaluates inspection results and provides repair recommendations based on program acceptance criteria.

The suppression chamber (wetwell) above the water level from elevation 472 feet 0 inches is coated with one coat of inorganic zinc coating. Approximately 4000 square feet of this coating do not meet ANSI N101.4 requirements because of damage. The damage to the coating will not result in the failure of the coating to adhere to its substrate. Regardless, the design of the ECCS strainers assumes the complete failure of the coating system and the entrainment of the resulting particles on the strainer bed following a LOCA.

There are an estimated 5000 square feet of unqualified organic paint in the drywell. Under certain postaccident conditions, the unqualified organic paint could fail in flakes and, therefore, has been evaluated as a potential source of debris which can clog emergency core cooling suction strainers. It is unlikely that all paint would fail simultaneously or that a significant portion of resulting paint flakes would be transported to the suppression pool. For conservatism, however, the design of the ECCS strainers is based on the complete failure of the unqualified coatings, their transport to the wetwell, and their eventual entrainment on the strainer beds.

Unqualified/Degraded Coatings in Containment

The Service Level I Coatings Program requires a log of the amount of unqualified degraded coatings within containment to be maintained. Following the most recent coatings inspection performed during the refueling outage 22 (R22) in the spring of 2015, the current amount of degraded coatings reported in the Degraded Coatings Log is less than 34 square feet out of the 100 square feet limit.

3.6.2 Containment Inservice Inspection Program

Containment integrity is verified through periodic inservice inspections conducted in accordance with the requirements of 10 CFR 50.55a. As identified in 10 CFR 50.55a, the requirements for containment inspections are contained in the ASME Boiler and Pressure Vessel Code, Section XI. More specifically, Subsection IWE provides the rules and requirements for ISI of Class MC pressure-retaining components and their integral attachments in light-water cooled plants.

The Fourth Ten Year Interval Containment Inservice Inspection Program Plan for Columbia Generating Station began on December 13, 2015. In accordance with 10 CFR 50.55a(g)(4)(ii) dated January 1, 2015, the Reference Code for the fourth ISI interval at Columbia is the ASME Boiler and Pressure Vessel Code Section XI, 2007 Edition, 2008 Addenda.

The referenced code is limited by conditions contained in 10 CFR 50.55a. The table 3.6.2-1 below identifies the exceptions applicable to Columbia relative to metal containments.

Table 3.6.2-1 10 CFR 50.55a Conditions to ASME Section XI	
10 CFR 50.55a Paragraph	**Description**
10 CFR 50.55a(b)(2)(ix) Section XI condition: Metal Containment Examinations	Applicants or licensees applying Subsection IWE, 1992 Edition with the 1992 Addenda, or the 1995 Edition with the 1996 Addenda, must satisfy the requirements of paragraphs (b)(2)(ix)(A) through (E) of this section. Applicants or licensees applying Subsection IWE, 1998 Edition through the 2001 Edition with the 2003 Addenda, must satisfy the requirements of paragraphs (b)(2)(ix)(A) and (B) and (b)(2)(ix)(F) through (I) of this section. Applicants or licensees applying Subsection IWE, 2004 Edition, up to and including the 2005 Addenda, must satisfy the requirements of paragraphs (b)(2)(ix)(A) and (B) and (b)(2)(ix)(F) through (H) of this section. Applicants or licensees applying Subsection IWE, 2004 Edition with the 2006 Addenda, must satisfy the requirements of paragraphs (b)(2)(ix)(A)(2) and (b)(2)(ix)(B) of this section. 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.

Table 3.6.2-1 10 CFR 50.55a Conditions to ASME Section XI	
10 CFR 50.55a Paragraph	**Description**
10 CFR 50.55a(b)(2)(ix)(A)(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 Columbia has not needed to implement any new technologies to perform inspections of any inaccessible areas at this time. However, Energy Northwest actively participates in various nuclear utility owners groups and ASME Code committees to maintain cognizance of ongoing developments within the nuclear industry. Industry operating experience is also continuously reviewed to determine its applicability to Columbia. Adjustments to inspection plans and availability of new, commercially available technologies for the examination of the inaccessible areas of the containment would be explored and considered as part of these activities**.**
10 CFR 50.55a(b)(2)(ix)(B) Metal Containment Examinations: Second Provision	When performing remotely the visual examinations required by Subsection IWE, the maximum direct examination distance specified in Table IWA–2210–1 may be extended and the minimum illumination requirements specified in Table IWA–2210–1 may be decreased provided that the conditions or indications for which the visual examination is performed can be detected at the chosen distance and illumination.

Table 3.6.2-1 10 CFR 50.55a Conditions to ASME Section XI	
10 CFR 50.55a Paragraph	**Description**
10 CFR 50.55a(b)(2)(ix)(J) Metal Containment Examinations: Tenth Provision	In general, a repair/replacement activity such as replacing a large containment penetration, cutting a large construction opening in the containment pressure boundary to replace steam generators, reactor vessel heads, pressurizers, or other major equipment; or other similar modification is considered a major containment modification. When applying IWE–5000 to Class MC pressure-retaining components, any major containment modification or repair/replacement must be followed by a Type A test to provide assurance of both containment structural integrity and leak-tight integrity prior to returning to service, in accordance with 10 CFR part 50, Appendix J, Option A or Option B on which the applicant's or licensee's Containment Leak-Rate Testing Program is based. When applying IWE–5000, if a Type A, B, or C Test is performed, the test pressure and acceptance standard for the test must be in accordance with 10 CFR 50, Appendix J.

Table 3.6.2-2 provides the inspection period and interval dates for the fourth ten-year interval.

Table 3.6.2-2 Fourth Inspection Interval Ending 12/12/2025			
Inspection Period	**Refueling Outage**	**From[1]**	**To[1]**
1	23 24	12/13/15 5/5/17 5/5/19	12/12/19 6/15/17 6/15/19
2	25	12/13/19 5/15/21	12/12/22 6/15/21
3	26 27	12/13/22 5/15/23 5/15/25	12/12/25 6/15/23 6/15/25
(1) Outage month/day are approximate and are included here for illustration purposes. Dates may change to correspond to outage schedule.			

IWE-1000 Scope and Responsibility

No areas identified meet IWE-1240 requirements for augmented examination.

IWE-2420 Successive Examinations

There are no successive examinations to be carried over from the third inspection interval.

Code Class MC Summary Tables

The following tables provide a summary of ASME Section XI examinations and tests for Code Class MC Components.

Table 3.6.2-3
Examination Category E-A Containment Surfaces

Item No.	Description	Exam Method	Required Exams	Deferral to End	Total Number	Number Required	Number 1st Period	Number 2nd Period	Number 3rd Period	RR No. / Code Case
	Containment Vessel									
E1.11	Accessible Surface Areas	General Visual	Accessible Surfaces	No	24	24	24	24	24	Note 1
E1.12	Wetted Surfaces of Submerged Areas	VT-3	100%	Yes	8	8	0	0	8	
E1.20	BWR Vent System Accessible Surface Areas	VT-3	100%	Yes	1	1	1	0	0	
E1.30	Moisture Barriers	General Visual	100%	No	1	1	1	1	1	

Note 1: General visual examinations of pressure retaining bolted connections may be performed with bolting in place under tension.

Table 3.6.2-4
Examination Category E-C Containment Surfaces Requiring Augmented Examination

Item No.	Description	Exam Method	Required Exams	Deferral to End	Total Number	Number Required	Number 1st Period	Number 2nd Period	Number 3rd Period	RR No. / Code Case
E4.11	Visible Surfaces	VT-1		No	0					Note 1
E4.12	Surface Area Grid	Ultrasonic Thickness		No	0					

Note 1: No areas identified meet IWE-1240 requirements for augmented examination.

Table 3.6.2-5
Examination Category E-G Pressure Retaining Bolting

Item No.	Description	Exam Method	Required Exams	Deferral to End	Total Number	Number Required	Number 1st Period	Number 2nd Period	Number 3rd Period	RR No. / Code Case
E8.10	Bolted Connections	VT-1	100%	Yes	4	4		4		

Note 1: Examinations may be performed while under tension unless the joint is disassembled. The items in this group refer to the containment hatches which are typically disassembled during refueling outages and therefore will require an examination once per interval while disassembled.

3.6.3 Supplemental Inspection Requirements

With the implementation of the proposed change, TS 5.5.12 will be revised by replacing the reference to RG 1.163 (Reference 1) with reference to NEI 94-01, Revision 3-A (Reference 2). This will require that a general visual examination of accessible interior and exterior surfaces of the containment for structural deterioration that may affect the containment leak-tight integrity be conducted. This inspection must be conducted prior to each Type A test and during at least three (3) other outages before the next Type A test if the interval for the Type A test has been extended to 15 years in accordance with the following sections of NEI 94-01, Revision 3-A:

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

In addition to the ASME Section XI, IWE examinations performed by the Inservice Inspection Program, the containment visual inspection performed prior to the performance of an ILRT in accordance with 10 CFR 50, Appendix J will satisfy the requirements of Section 9.2.1 and 9.2.3.2 of NEI 94-01 Revision 3-A.

3.6.4 Maintenance Rule Inspections

An appropriate program has been developed and implemented to meet the requirements of 10 CFR 50.65, Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," (the Maintenance Rule). The most recent periodic assessment, per paragraph (a)(3) of the Maintenance Rule, indicates that the program for monitoring the condition and effectiveness of structures is appropriate and meets the intent of the Maintenance Rule.

The Maintenance Rule Structural Baseline Inspection Program is described in Technical Services Instruction SYS-4.23, "Maintenance Rule Structural Baseline Inspections." The Maintenance Rule Program also reviews all Condition Reports (CR). CRs that may involve structural aspects of the containment are evaluated to determine if there has been a functional failure. No functional failures of the containment have been identified. The Columbia primary containment is currently in Maintenance Rule (a)(2) status.

3.6.5 Uninspectable Surfaces

There are inaccessible areas of the Columbia primary containment, including essentially the entire outside surface and parts of the inner surface blocked by concrete (for example the bottom head). There are no programs that monitor the condition of the inaccessible areas of the containment shell directly. However, leak-tightness of the containment shell is assessed periodically by measuring humidity in the sand pocket drains located at the base of the containment vessel. Sand pocket data has been taken during outages pre- and post- annulus flood up during refueling operations starting in 1988. The measurement is made using a vacuum pump and a hygrometer to measure

the sand pocket relative humidity (RH). The dry-bulb temperature (temperature of air measured by a thermometer freely exposed to the air but shielded from radiation and moisture) is also taken. Both the sand pocket RH and dry bulb temperature are recorded.

Regardless of pre- or post- flood up conditions, the sand pocket humidity is a good indicator of annulus leakage during refueling operations and changing conditions such as detecting small leaks through the metal containment liner. Given the average dry bulb temperature and the average suppression pool temperature, the RH required for condensation to occur on the containment liner is 60% or greater. At normal suppression pool temperatures of 75 degrees F, condensations will not occur without RH values in the 90% range.

Portions of the Columbia containment shell are submerged in the suppression pool. The submerged surfaces that are not covered by concrete are accessible and a portion is examined each refueling outage cycle.

3.6.6 Primary Containment Leakage Rate Testing Program - Type B and Type C Testing Program

Columbia Types B and C testing program requires testing of electrical penetrations, airlocks, hatches, flanges, and CIVs in accordance with 10 CFR 50, Appendix J, Option B and RG 1.163 (Reference 1). The results of the test program are used to demonstrate that proper maintenance and repairs are made on these components throughout their service life. The Types B and C testing program provides a means to protect the health and safety of plant personnel and the public by maintaining leakage from these components below appropriate limits. In accordance with TS 5.5.12, the allowable maximum pathway total Types B and C leakage is 0.6 L_a (72,922 sccm) where L_a equals approximately 121,536 sccm at standard atmospheric conditions.

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

A review of the Type B and Type C test results from 2007 through 2015 for Columbia has shown substantial margin between the actual As-Found (AF) and As-Left (AL) outage summations and the regulatory requirements as described below:

- The AF minimum pathway leak rate average for Columbia is 16% of 0.6 L_a with the highest value 28.08% 0.6 L_a.

- The AL maximum pathway leak rate average for Columbia is 22% of 0.6 L_a with a high of 29.17% 0.6 L_a.

Table 3.6.6-1 provides LLRT data trend summaries for Columbia inclusive of the 2007 ILRT.

Table 3.6.6-1
Columbia Type B and C LLRT Combined As-Found / As-Left Trend Summary

RFO	2007	2009	2011	2013	2015
	R18	R19	R20	R21	R22
AF Min Path (SCCM)	13,191	20,482	9,482	6,387	8932
Fraction of 0.6 La (percent)	18.09%	28.08%	13.00%	8.76%	12.25%
AL Max Path (SCCM)	13,819	13,622	21,270	14,170	17,678
Fraction of 0.6 La (percent)	18.95%	18.68%	27.17%	19.43%	24.24%
AL Min Path (SCCM)	6,749	6,939	13,966 (1)	5,014	6,359
Fraction of 0.6 La (percent)	9.26%	9.52%	19.15%	6.87%	8.72%

(1) The increase in AL MNPLR value was attributed to LLRT failure of TIP-V-3 following actuator replacement. The as-left condition was evaluated for containment operability and accepted with substantial margin to the overall containment acceptance limit of 0.6La (72,922 sccm). The valve was subsequently replaced during Maintenance Outage MO-12-01 prior to R21. The MO-12-01 LLRT values for TIP-V-3 were (as-found = 6630 sccm) with an as-left value of 24 sccm following TIP-V-3 replacement.

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

Table 3.6.7-1 identifies the components that were on extended intervals and have not demonstrated acceptable performance during the previous two outages.

Table 3.6.7-1 Columbia Type B and C LLRT Program Implementation Review						
R21 - Spring 2013						
Component	**As-Found SCCM**	**Admin Limit SCCM**	**As-Left SCCM**	**Cause of Failure**	**Corrective Action**	**Scheduled Interval**
CIA-V-21	466	110	2	Seat area degradation	Replaced Valve	30 Months
RRC-V-19	217	148	107	Minor debris in seat area	System Flushed	30 Months
EDR-V-20	2,940	1000	AL=1090 – Leak Rate Accepted per Evaluation	Seat degradation	In-body wedge/seat lapping	30 Months
R22 - Spring 2015						
Component	**As-Found SCCM**	**Admin Limit SCCM**	**As-Left SCCM**	**Cause of Failure**	**Corrective Action**	**Scheduled Interval**
EDR-V-20	7063	1000	362	Seat degradation	In-body wedge/seat lapping	30 Months
RRC-V-19	554	148	6.5	Seat degradation	Replaced Valve	30 Months

The following list shows LLRT tested components at Columbia that had repetitive failures since 2005. In all cases, the overall pathway calculation for the period in which the failures occurred remained under 0.6La.

Penetration X-23 – EDR-V-19

R-17 (2005): As-found leak rate measured to be 13,540 sccm. Valve was flushed with demineralized water. As-left leakage rate measured to be 25.2 sccm.

R-18 (2007): As-found leak rate measured to be 817 sccm. Leakage was attributed to debris found on valve seat. High volume flush was performed to remove debris. As-left leakage rate measured to be 184 sccm.

Penetration X-23 – EDR-V-20

- R-17 (2005): As-found leak rate measured to be 5,280 sccm. Leakage was attributed to debris found on valve seat. High volume flush was performed to remove debris. As-left leakage rate measured to be 320 sccm.

- R-18 (2007): As-found leak rate measured to be 5,367 sccm. Leakage was attributed to debris found on valve seat. The in body of the valve was cleaned and an actuator overhaul was performed. As-left leakage rate measured to be 367.5 sccm.

- R-19 (2009): As-found leak rate measured to be 3,700 sccm. Leakage was attributed to debris found on valve seat. High volume flush was performed to remove debris. As-left leak rate measured to be 130 sccm.

- R-20 (2011): As-found leak rate measured to be 4,800 sccm. Leakage was attributed to debris found on valve seat. High volume flush was performed to remove debris. As-left leak rate measured to be 484 sccm.

- R-21 (2013): As-found leak rate measured to be 2,940 sccm. Leakage was attributed to debris found on valve seat. The in body of the valve was cleaned and in-body wedge/seat lapping was performed. As-left leak rate measured to be 1090 sccm.

- R-22 (2015): As-found leak rate measured to be 7063.3 sccm. Leakage was attributed to debris found on valve seat. In body of valve was cleaned and in-body wedge/seat lapping was performed. As-left leak rate measured to be 71.0 sccm.

The failures listed for valves EDR-V19 and EDR-V-20 did exceed their respective administrative limit; however, the penetration X-23 leakage did not have a significant impact on the overall summation for containment La. The planned corrective action for

these valves is to replace the valves with a different style valve more suitable for passing debris. This will enhance the valve seating capability.

Penetration X-56 – CIA-V-21

- R-20 (2011): As-found leak rate measured to be 1380 sccm. Leakage was attributed to debris on valve seat. The soft seat was replaced on the valve. As-left leak rate measured to be 140 sccm.

- R-21 (2013): As-found leak rate measured to be 466 sccm. Leakage was attributed to debris on the valve seat. The valve was replaced. As-left leak rate measured to be 2 sccm.

Penetration X-77Aa – RRC-V-19

- R-21 (2013): As-found leak rate measured to be 217 sccm. Leakage was attributed to debris on valve seat. Flush was performed to remove debris. As-left leak rate measured to be 107 sccm.

- R-22 (2015): As-found leak rate measured to be 554 sccm. Leakage was attributed to seat degradation. The valve was replaced. As-left leak rate measured to be 6.5 sccm.

Penetration X-77Aa – RRC-V-20

- R-19 (2009): As-found leak rate measured to be 156 sccm. The leak rate was accepted as-is.

- R-20 (2011): As-found leak rate measured to be 182 sccm. The leak rate was accepted as-is.

Penetration X-77Ac – PSR-V-X77A/1

- R-17 (2005): As-found leak rate measured to be 35,180 sccm. A repair of the penetration was not performed during the refueling outage; however, the penetration was isolated using valve PSR-V-101. As-left leak rate measured to be 8.8 sccm of the companion valve. PSR-V-X77A/1 was subsequently replaced in R-18.

- R-18 (2007): As-left leak rate measured to be 418 sccm.

Penetration X-89B – CIA-V-31A

- R-19 (2009): As-found leak rate measured to be 927 sccm. Valve was disassembled and repaired. As-left leak rate measured to be 17 sccm.

- R-20 (2011): As-found leak rate measured to be 6,730 sccm. Valve was replaced. As-left leakage rate measured to be 1 sccm.

3.7 Operating Experience

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

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

- Information Notice (IN) 1992-20, "Inadequate Local Leak Rate Testing"
- IN 2004-09, “Corrosion of Steel Containment and Containment Liner”
- IN 2010-12, "Containment Liner Corrosion"
- IN 2011-15, “Steel Containment Degradation and Associated License Renewal Aging Management Issues”
- IN 2014-07, "Degradation of Leak-Chase Channel Systems for Floor Welds of Metal Containment Shell and Concrete Containment Metallic Liner"
- Regulatory Issue Summary (RIS) 2016-07, “Containment Shell Liner Moisture Barrier Inspection.”

Each of these areas is discussed in detail in Sections 3.8.1 through 3.8.6, respectively.

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

The NRC issued IN 92-20 to alert licensees of problems with local leak rate testing two-ply stainless steel bellows used on piping penetrations at four different plant: Quad Cities, 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 since, during testing, the two plies in the bellows were in contact with each other, restricting the flow of the test medium to the crack locations. Any two-ply bellows of similar construction may be susceptible to this problem. 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:

NRC IN 92-20, informed licensees that two-ply stainless steel bellows can be susceptible to transgranular stress corrosion cracking and the leakage through them may not be detectable by Type B testing. No such bellows exist in the Columbia containment pressure boundary.

In addition, two events were described involving leaking flanges which occurred because licensees failed to consider all possible leakage paths when they established their leak rate test programs. The licensees identified the valves as containment isolation barriers, but failed to consider the gasketed flanges as leakage paths.

Gasketed flanges are considered to be potential leak rate paths at Columbia and are included in the LLRT program. When these gasketed flanged valves are perturbed, an Appendix J Quantitative Analysis or visual examination is performed. Containment valves that are tested in the reverse direction have had their seals evaluated for adequacy of the method of testing. The testing methodology for these valves has been accepted by the NRC. The leak rate testing program is maintained through the work order (WO) process by requiring the appropriate operability test for containment valves which have been perturbed.

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

The NRC issued IN 2004-09 to alert addressees to recent occurrences of corrosion in freestanding metallic containments and in liner plates of reinforced and pre-stressed concrete containments. Any corrosion (metal thinning) of the liner plate or freestanding metallic containment could change the failure threshold of the containment under a challenging environmental or accident condition. Thinning changes the geometry of the containment shell or liner plate and 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 junctions is important in avoiding conditions favorable to corrosion and thinning of the

containment liner plate material. Inspections of containment at the floor level, as well as at higher elevations, have identified various degrees of corrosion and containment plate thinning.

Discussion:

Columbia does not have a containment liner. The containment vessel is a free standing all metal vessel. It would be susceptible to corrosion if there were a breakdown of the protective coating or if there is water intrusion between it and the concrete biological shield (referred to hereafter as the bioshield). The containment vessel is subject to periodic examination for corrosion in accordance with ASME Section XI, Subsection IWE. The last general inspection for corrosion was performed during the spring 2015 R22 outage. As noted in Section 3.7.7.4, there was some degradation of non-pressure boundary components that were entered into the corrective action process however, there were no reported indications that warrant repair or successive examinations.

A review of the related generic communications from the NRC in IN 89-79, “Degraded Coatings and Corrosion of Steel Containment Vessels” and IN 97-29, “Containment Inspection Rule” were performed and both are addressed within the current programmatic activities.

3.7.3 IN 2010-12, "Containment Liner Corrosion"

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

Discussion:

Columbia has 2-inch flexible (compressible) foam installed with adhesive cement on the backside of the primary containment vessel prior to pouring the bioshield wall. Additionally, the foam work for placement of the concrete for the bioshield wall included installation of the one-quarter inch thick pre-molded fiberglass reinforcement polyester epoxy panels cemented on the outside (away from the vessel wall) of the polyurethane foam. This foam layer with the fiberglass prevents the steel containment vessel from being in contact with the concrete of the bioshield wall. Thus, any foreign material left in the concrete either by design or accident will not interact with the containment vessel steel. As described in Section 3.1, a sand filled pocket area is provided at the surrounding exterior of the primary containment vessel near the base. The sand filled

pocket area is used to collect any drainage between the primary containment vessel exterior and the biological shield wall. These sand pocket annulus drains are periodically checked for evidence of moisture (Reference Section 3.6.5 Uninspectable Surfaces). As described in Section 3.9.2 a one-time borescope inspection of the sand pocket drain lines was performed to confirm the absence of clogged drains and that a flow path exists for identification of any potential leakage into the sand pocket region. Unexpected inspection results will be documented under the Columbia corrective action program.

As committed to in NUREG 2123 Appendix A Item 64 for License Renewal, Columbia plans to remove primary containment inspection ports in the containment vessel at 570 foot elevation to check for evidence of leakage. Port inspections will be performed during a refueling outage while the reactor cavity is flooded.

3.7.4 IN 2011-15, "Steel Containment Degradation and Associated License Renewal Aging Management Issues"

IN 2011-15 was issued to inform the industry of recent issues identified by the NRC staff concerning degradation of nuclear power plant steel containments that could impact aging management of the containment structures during the period of extended operation of a renewed license. These issues included degraded torus coatings at multiple plants which lead to localized (pitting) corrosion of the containment and the discovery of water in inaccessible areas of containment at several other plants. Water that may be in contact with the steel liner or containment plate can cause corrosion that may result in wall thinning. Water in inaccessible areas is of particular concern as corrosion could go undetected for years and possibly result in loss of material (wall thinning) to less than the minimum design thickness.

The IN provides some suggestions for managing age-related degradation so that the intended function of the containment will be maintained through the period of extended operation if pitting corrosion of the torus containment liner or water in inaccessible areas of containments is identified. In each of the cases, the identified plants were required to make specific commitments during license renewal reviews.

<u>Discussion:</u>

Columbia does not have a torus, but does have a coating on the submersed surfaces of the wetwell. Loss of this coating would expose the interior side of the primary containment vessel to a water environment which could result in corrosion of this surface. The coatings within containment are managed by the Service Level 1 Protective Coatings Program. This is an existing program that monitors the performance of Service Level 1 coated surfaces inside containment through periodic coating examinations, condition assessments and remedial actions including repair or testing. Ensuring the quality of the coating applied to the steel containment serves to prevent or minimize loss of material (thickness) due to corrosion. Additionally, the

existing ISI-IWE program at Columbia performs visual inspections of the wetted surfaces of submerged areas of containment for signs of corrosion in accordance with ASME Section XI, Subsection IWE and per the guidance of the ISI Program Plan.

Columbia does have an annulus (air gap filled with sand) area between the back side of the primary containment vessel and the bioshield wall. This is very similar to the configuration to Hope Creek which was identified in the IN with regard to the issue of water discovered in inaccessible areas of the containment. Like Hope Creek, the refueling bellows seal at Columbia is located at the top of this air gap and would be the most likely potential source of leakage into this air gap. The configuration of the primary containment vessel and this air gap at Columbia has a sand pocket region at the bottom of this air gap. The sand pocket region has eight drain lines equally spaced around the circumference to drain any potential water from this area which if left in the air gap could result in undetected corrosion. Currently, these drain lines are checked for the presence of water every 28 days under a preventative maintenance task by having an operator open the valve at the bottom of the drain line and check for water. To date, no water has been found during these checks. Additionally, humidity levels in the sand pocket region are checked prior to reactor cavity flood-up and post drain down of the cavity under a preventative maintenance task. This is meant as a check for gross leakage past the refueling bellows which could introduce water into the air gap. Humidity levels have been acceptable to date. Another indicator of potential leakage into the air gap from the refueling bellows seal would be from a fuel pool cooling flow indicating switch 21. There are five drain lines from the region of the containment above the air gap and below the refuel bellows seal. Based on their configuration any leakage past the bellows seal should flow into these drain lines. The fuel pool cooling flow indicating switch is in a drain line off the header that these five drain lines feed into and downstream of where these drain lines connect to the header. These five drain lines are the only lines that tie into this header. This flow indicating switch alarms in the main control room when flow of greater than 1.0 gallons per minute (gpm) is detected. Search of the control room logs and the corrective action database found no occurrence of this alarm coming in.

This IN also identifies that Hope Creek had water backed up in the air gap and flowed out through a containment penetration sleeve due to four of the drain lines being plugged by material left in the lines since construction. The drain lines at Columbia were also found to be plugged (no free flow path) at the end of construction (approximately 1983). This was discovered when water seeped through the bioshield wall at the penetration sleeves. Six of the lines were cleaned out at that time and verified to have a free flow path. Two of the drain lines are located in the reactor building truck bay were blind flanged at the time and not checked. In response to IN 86-99, “Degradation of Steel Containments,” all drain lines were checked again in 1987 and two of the original six checked were again found plugged. Additionally, the two in the truck bay were inspected and found to be plugged. All were cleaned and a borescope inspection performed to verify free flow paths existed. The drain lines in the truck bay were provided valves to allow a weekly check of all these drain lines for the presence of

water. This was changed to a monthly (28 day) check around 1991 as the weekly checks did not find any water in these drain lines.

Coating defects discovered during inspections have been minimal to date and include the concrete surfaces (columns, slab and pedestal) in the wetwell. Refer to section 3.7.7.2 for the most recent (R22) inspection. Containment surfaces inspected under the ISI-IWE program have satisfied the acceptance standards without exception. There are no containment surfaces requiring designation as augmented examination areas.

Based on successful completion and results of the preventative maintenance tasks discussed above, there is high confidence that water is not and has not been present for some time in the air gap between the primary containment vessel and the bioshield wall. Additionally, an engineering evaluation has been performed to determine the potential loss of material from the primary containment vessel if the air gap was filled with water from the beginning of operation and left that way until the end of the period of extended operation or for a period of sixty years. This evaluation determined that the even with the expected loss of material on the primary containment vessel due to the scenario of standing water in the air gap, the PCV will still provide adequate thickness required by design loads associated with the primary containment vessel. Therefore, the significance of this issue (water in inaccessible areas of containment) is minimal. Commitments associated with the sand pocket region of the Columbia containment vessel are discussed in Section 3.9.2 of this submittal.

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

The NRC issued IN 2014-07 to inform the industry of issues concerning degradation of floor weld leak-chase channel systems of steel containment shell and concrete containment metallic liner that could affect leak-tightness and aging management of containment structures. Specifically, this IN provides examples of operating experience at some plants of water accumulation and corrosion degradation in the leak-chase channel system that has the potential to affect the leak-tight integrity of the containment shell or liner plate. In each of the examples, the plant had no provisions in its ISI plan to inspect any portion of the leak-chase channel system for evidence of moisture intrusion and degradation of the containment metallic shell or liner within it. Therefore, these cases involved the failure to perform required visual examinations of the containment shell or liner plate leak-chase systems in accordance with the ASME Code Section XI, Subsection IWE, as required by 10 CFR 50.55a(g)(4).

The containment basemat metallic shell and liner plate seam welds of pressurized water reactors are embedded in a 3 feet by 4 feet concrete floor during construction and are typically covered by a leak-chase channel system that incorporates pressurizing test connections. This system allows for pressure testing of the seam welds for leak-tightness during construction and also while in service, as required. A typical basemat shell or liner weld leak-chase channel system consists of steel channel sections that are

fillet welded continuously over the entire bottom shell or liner seam welds and subdivided into zones, each zone with a test connection.

Each test connection consists of a small carbon or stainless steel tube (less than 1-inch diameter) that penetrates through the back of the channel and is seal-welded to the channel steel. The tube extends up through the concrete floor slab to a small access (junction) box embedded in the floor slab. The steel tube, which may be encased in a pipe, projects up through the bottom of the access box with a threaded coupling connection welded to the top of the tube, allowing for pressurization of the leak-chase channel. After the initial tests, steel threaded plugs or caps are installed in the test tap to seal the leak-chase volume. Gasketed cover plates or countersunk plugs are attached to the top of the access box flush with the containment floor. In some cases, the leak-chase channels with plugged test connections may extend vertically along the cylindrical shell or liner to a certain height above the floor.

Discussion:

As noted in the subject IN, the leak-chase channel system is typical of PWR containment configurations and is not applicable to Columbia which is a BWR. The primary containment vessel (PCV) at Columbia is a free-standing metal containment which does not utilize the aforementioned leak-chase channel system. The metal containment of Columbia does have an annulus (air gap) between the PCV and bioshield wall concrete. A leak into this area could result in unmonitored degradation on the backside of the PCV steel plate. However, this has already been addressed for Columbia under evaluation of IN 2011-15 'Steel Containment Degradation and Associated License Renewal Aging Management Issues' and during the license renewal process. Also, Columbia's containment configuration has a moisture barrier where the PCV interfaces with the concrete slab in the wetwell. This is a potential leak path, but does not have a 'leak-chase channel' associated with the moisture barrier. However, this moisture barrier is within the scope of Columbia's ISI-IWE program and is inspected periodically per the ASME Code.

3.7.6 NRC RIS 2016-07, “Containment Shell or Liner Moisture Barrier Inspection”

The NRC staff identified several instances in which containment shell or liner moisture barrier materials were not properly inspected in accordance with ASME Code Section XI, Table IWE-2500-1, Item E1.30. Note 4 (Note 3 in editions before 2013) for Item E1.30 under the “Parts Examined” column states, “Examination shall include moisture barrier materials intended to prevent intrusion of moisture against inaccessible areas of the pressure retaining metal containment shell or liner at concrete-to-metal interfaces and 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 barriers, 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.

Discussion

Columbia complies with 10 CFR 50.55a and ASME Section XI, 2007 Edition with 2008 Addenda, which directs the inspection of containment non-welded moisture barriers in Subsection IWE, Table IWE-2500-1, Examination Category E-A. The Columbia primary containment vessel is a free-standing steel pressure vessel with a Mark II over-under configuration for pressure suppression. The containment vessel is enclosed in a reinforced-concrete biological shield wall which, is separated from the reinforced concrete by an annulus of compressible isolation material, approximately 2 inches thick. The primary containment vessel is anchored to the concrete mat foundation and the bottom of the suppression chamber is lined on the inside with reinforced concrete.

There are three moisture barriers for this design. Two are sealants and the third is welded and therefore, exempt:

1. The moisture barrier between the steel vessel and concrete structure at the concrete-to-vessel interface inside containment. This moisture barrier is a sealant and is tracked in the ISI Program Plan and is inspected in accordance with ASME Section XI.

2. The moisture barrier at the vessel to concrete mat interface in the inaccessible region outside of the vessel. This moisture barrier is a sealant and is inaccessible and therefore exempt from inspection per IWE-1220(b).

3. The moisture barrier located at the top head refuel bellows prevents moisture from getting between the containment vessel and refuel cavity during refueling outage flood-up. The top head bellows barrier is welded in place, therefore, ASME Section XI Item E1.30 examinations are exempted per Figure IWE-2500-1, Note 3.

Based on the above review, Columbia is in compliance with ASME Section XI, IWE. Furthermore, in compliance with 10 CFR 50.55a(b)(2)(ix)(A)(1), Columbia checks for moisture between the containment vessel and concrete structure through periodic operation of the sand pocket drain valves.

3.7.7 Results of Recent Containment Inspections – Problem Identification Reports

3.7.7.1 Refueling Outage 21 (R21) Coating Inspection Report

During R21, the drywell containment liner, piping and coated steel surfaces, the concrete floor and pedestal were examined. Overall condition is good with the following exceptions noted:

No coating repairs were performed during R21. The following issues were identified:

1. Approximately 1,727 square feet of random to general blistering, random cracking with isolated delamination, and general mechanical damage were identified on elevation 501' floor of the drywell. No coating repairs were necessary. The floor was lightly scraped to remove blistered and delaminated coating leaving the remaining floor coating tightly adhered.

2. Approximately 844 square feet of cracked coating with random delaminating and disbanded areas were observed on the coated concrete on the interior (under vessel) of the reactor pedestal.

<u>Drywell Coated Carbon Steel</u>

The epoxy coated carbon steel containment liner, structural steel and piping are generally in good condition with random mechanical damage (heavier damage was observed in high traffic areas). Areas of exposed substrate generally exhibit light surface rusting. Isolated areas of exposed carbon steel piping, which are susceptible to sweating, exhibit heavier surface rusting and were recommended to be monitored periodically for metal loss. Piping coated with inorganic zinc coating is in generally good condition with no observable rusting.

<u>Coated Concrete (Floor at Elevation 501')</u>

The drywell floor coating system at elevation 501' is degraded and exhibits random to general blistering, random cracking with isolated delamination, and general mechanical damage. Blistering ranges generally from ASTM D714 standard rating of No. 6 to No. 2 with isolated blisters observed up to ½ inch diameter. Blister caps are a combination of intact, fractured and totally removed due to foot traffic. The location of the degraded coating is more critical since the floor coatings are adjacent to the downcomer openings to the suppression chamber. No coating repairs were necessary. The floor was lightly scraped to remove loose, blistered and delaminated coating leaving the remaining floor coating tightly adhered.

Coated Concrete on the Reactor Pedestal (exterior)

Cracking of the coating on the exterior reactor pedestal has been historically documented during previous outages. The cracking generally appears to be adhered to substrate. However, some isolated delamination was observed.

Coated Concrete on the Reactor Pedestal (interior)

Cracking of the coating on the interior reactor pedestal has been historically documented during previous outages. The cracking appears to be to substrate with some cracking in between coats. The topcoat appears to be tightly bonded. Random delamination and disbanding was observed below elevation 501' and above. Disbonded coating was observed on the immersed floor. Approximately 844 square feet of cracked coating with random delaminating and disbanded areas were observed on the coated concrete on the interior (under vessel) of the reactor pedestal. No coating repairs were necessary.

The following degraded coatings were identified for future repair and added to the Degraded Coatings Log:

1. A total of 19 square feet of delaminating topcoat on the interior surfaces of the four drywell circulating fan housings were observed. Work orders were generated for future repair.

2. Approximately 0.5 square feet of degraded coating was found on RCC-V-40. A WO was generated for future repair. As a conservative measure, 1 square foot of degraded coating was logged in the Degraded Coatings Log.

3. Approximately 1 square foot of degraded coating was found on the elevation 512' catwalk. A WO was generated for future repair.

4. Approximately 3 square feet of delaminating top coat was observed on a fan motor box on elevation 584'. A WO was initiated for future repair.

Conclusion

The Columbia drywell coatings are in an overall good condition and are acceptable for the next operating cycle. Some areas of concern were noted during the inspection. No coating repairs were performed during the outage. Previously identified coating work was moved to R22 along with the work identified in R21.

3.7.7.2 Refueling Outage (R22) Coating Inspection Report

The R22 Coating Inspection identified the overall condition of the containment coatings as good. General areas of rust at what appear to be welded connections on the reactor

closed cooling (RCC) system piping remain but with little change from R21 in both the drywell and wetwell. The repaired coating on a reactor closed cooling system primary containment isolation valve RCC-V-40 is showing signs of degradation due to inadequate surface preparation. Areas requiring repair were repaired per the guidance of the Coatings Engineer. Subsequent inspections will be performed during R23 to document any changes and recommend repairs as necessary.

Several areas of degraded coating were repaired this outage, most significantly the 27 square feet of degraded coating on the reactor pedestal that was first reported in R18. This repair regained a significant amount of the 100 square feet coatings margin. No coating repair was performed in the wetwell during R22. At the close of R22, the current amount of degraded coating reported in the Degraded Coatings Log is less than 34 square feet out of the 100 square feet limit.

Primary Containment Sacrificial Shield Wall Coatings

The epoxy coated carbon steel containment liner and structural steel are generally in good condition with random mechanical damage areas. Areas of exposed substrate generally exhibit light surface rusting.

Several areas of rusting at the weld interface were identified on pipe supports, hangers and embedded plates.

Coated Concrete (Floor at Elevation 501')

The Drywell floor coating system at elevation 501' is degraded and exhibits random to general blistering, random cracking with isolated delamination, and general mechanical damage. The mechanical damage is primarily at the 501' elevation in the workers travel path areas due to impacts and scrapes from the movement of equipment and wear from foot traffic.

Blistering identified on the floor and reported in the R21 report has not exhibited any significant changes since the last inspection.

Primary Containment Pedestal Coatings (exterior)

Cracking of the coating system of the exterior reactor pedestal has been historically documented during previous refueling outages. The cracking generally appears to be adhered to the substrate. However, some isolated delamination was observed. No significant changes were noted since the last inspection. During R22 a WO was executed which repaired 27 square feet of the exterior reactor pedestal.

Primary Containment Undervessel Coatings (interior)

A remote visual inspection was performed under the reactor vessel and in the sump pit using a remote camera system equipped with pan, tilt and zoom. Cracking of the coating system on the interior reactor pedestal has been historically documented during previous outages and does not exhibit any significant changes since R21.

Two pipes penetrating from the outboard pedestal wall in the sump pit exhibit rust along 75 percent of the entire run of the pipe. There appears to be rust scale on the underside of both pipes near the wall penetration.

Drywell General Coatings

Approximately thirteen of the inorganic zinc coated main steam safety relief valve (SRV) lines exhibit rusting on the flange to pipe weld interface and bolting hardware. These areas have been identified in previous reports and should be periodically monitored for metal loss. There was no apparent loss of material noted during this inspection. Several areas exhibited rusting on pipe weld joints and piping. There were areas of rusting on some support brackets and struts noted also.

Drywell circulating fans exhibit delaminating topcoat on the interior surfaces of the fan housings. These areas were previously identified during the R21 inspection. No significant changes were identified since the last inspection. Work to repair the coating was deferred, however, the observed loose coating was removed to avoid delamination and potential strainer plugging. Less than 2 square feet of debris was removed. Coating repairs are currently scheduled for the R23 refueling outage.

Wetwell Coatings

The inorganic zinc coated outboard wall exhibits isolated patches of pinpoint rusting and mechanical damage with surface rust. The epoxy and inorganic zinc coated portions of the carbon steel downcomers and concrete support columns appear to be in good condition with no identifiable degraded coating. General rusting was identified on all uncoated carbon steel downcomer piping, associated piping supports, hangers, carbon steel that supports the drywell floor seal and patches on the underside of the catwalk shell plates.

Conclusion

The Columbia containment coatings are in an overall good condition and are acceptable for the next operating cycle. There were no new areas of concern noted during the inspection. Four of the nine coating tasks planned for R22 were addressed either by repair or removal of loose coating to regain margin in the Degraded Coatings Log. The CRA fan work was deferred to coincide with other fan maintenance. The Degraded Coatings Log was updated to reflect the current estimate, which stands at less than 34

square feet of degraded coating out of the 100 square feet limit. Continued monitoring of the coating conditions under the Protective Coatings Program is performed under scheduled PMs to ensure the coatings remain intact and are repaired, as needed.

3.7.7.3 R21 IWE Examinations

No IWE containment examinations were conducted during the R21 refueling outage.

3.7.7.4 R22 IWE Examinations

All ISI period containment inspection requirements were met during the R22 refueling outage. Details of these examinations are provided in the R22 IWE Examinations summary.

Columbia performed the vessel containment inspections in accordance with the IWE guidance as given in ASME Section XI, 2001 Edition with the 2003 Addenda. A review of the inspection reports from the last two outages (R21 and R22) show no recordable indications reported. Note that there were no IWE examinations in R21, the period requirements were all met through inspections in R22.

The R22 containment inspections consisted of both General Visual (GV) and VT-3 qualified examinations utilizing ISI direct and remote examination techniques. General visual inspections were conducted on accessible internal surfaces of the containment at elevations 471’, 501’, 522’, 548’ and 572’ including the containment surfaces both above and below the waterline, access hatches and moisture barriers. Discoloration was noted at elevation 553’ from 45 to 90 and 180 to 270 azimuths adjacent to the residual heat removal (RHR) containment spray header. Additionally minor surface oxidation was noted intermittently on all quadrants and elevations with no evidence of material loss.

An inspection was performed of the suppression chamber submerged surfaces utilizing dive certified VT-3 examiners applying direct visual examination. Areas examined consisted of the containment shell welds and stiffeners from 0 to 360 azimuths. Edges of stiffener flanges exhibited random areas of nicked coating. There were also isolated areas of mechanical damage noted on the shell and stiffeners. Blistered coating was identified on the shell and stiffeners ranging from a size 2-8 few to medium per ASTM-D-710. All conditions were evaluated as acceptable. The bottom head moisture barrier at elevation 446’ was inspected with no indications noted. The area between 25 and 70 degree azimuth was noted as inaccessible due to ECCS strainers. In summary the R22 examinations noted some degradation of non-pressure boundary components that were entered in to the Columbia corrective action program as applicable. There were no reported indications that warrant repair or successive examinations.

3.7.7.5 R19 Maintenance Rule Structural Inspections

Wetwell

The R19 Maintenance Rule Structural Inspection concluded the general condition of the wetwell structural steel components is good. The inspection mainly looked at steel components such as the omega seal and support, the catwalks and supports, the containment liner, containment stiffeners, CVB platforms and support steel, the drywell slab support (radial) beams and metal floor decking for the drywell floor slab. These components are above the waterline of the suppression pool, but below the drywell slab. Thus, these components are in an environment conducive to corrosion and many of these carbon steel components have corrosion deposits on them, However, there is no evidence of material loss due to corrosion and the carbon steel components are still structurally sound.

Drywell

The R19 Maintenance Rule Structural Inspection concluded the general condition of the drywell is good. Inspection was performed from the many permanent platforms installed in the drywell and from the top of the sacrificial shield wall (SSW) at the stabilizer truss. The major concrete components inspected were the floor slab between the drywell and wetwell and the reactor pedestal which extends from the floor slab to the bottom of the (SSW). The steel components inspected included the SSW, containment vessel liner wall, platforms, radial beams and beam seats at vessel liner, stabilizer truss, downcomer jet deflector, stairs and ladders. This area is inerted with nitrogen during normal plant operations. No conditions requiring initiation of a condition report (CR) were noted during this inspection. The concrete floor slab and reactor pedestal were in very good condition. There does not appear to be any active cracks or spalling as the coating on both of these surfaces is intact except for small chips in the pedestal coating just below the SSW near the stairwell at the equipment hatch. The appears to have been some 'bug holes' in the reactor pedestal at the time of construction, but these have been covered by the coating and remain covered/filled by this original coating. There is some discoloration of the floor slab coating and staining of the pedestal coating, but this looks to be from work activities during outages and not from loss of material due to corrosion of any steel in the drywell.

The steel components in the drywell were also in very good condition. The vast majority of the steel components inspected still had their coating intact. Some had small areas of the coating missing, but there was no evidence of any loss of material due to corrosion. One particular steel component with coating missing is a 'box' beam for the pipe whip support at el. 512' just before ladder going to upper platforms. This missing coating is most likely due to maintenance activities in the drywell such as removal of this beam for movement of the RRC pump and/or motor (evident by new bolts & nuts installed in splice plate). The bolts and nuts were all installed (no empty holes in splice plate) and tightened. All other connectors noted during inspection appeared to be tightened (bolt

heads and nuts snug against mating surfaces). Some of the jet deflectors near the equipment hatch had areas of coating chipped off and signs of corrosion were present. These should be inspection again in R20 for trending of any potential material loss due to this coating damage and presence of corrosion. There was no loss of material at this time in R19. The beam seats for radial beams appeared to be in very good condition. No signs of corrosion at these. The monorail for the RRC motor hoist also had minor corrosion deposits on the upper and lower flange near Az 180. There was no loss of material noted and this condition will be monitored again in R20 to trend any potential change in condition of this component. Additionally, the vessel liner is 'stained' between AZ 240 and AZ 270 and el. *550'* and 560'. This staining was from one of the containment recirculation air (CRA) cooling coils and has been previously documented under the site corrective action program and in the CRA system health report. The cause of this staining has been corrected and the station has decided to leave the stain as-is. No further monitoring of this condition is required. Some of the stabilizer units at el. 568' have small portions of the coating chipped off. Again, this appears to be from maintenance activities associated with outages rather than age related failure of the coating. No corrosion was present and no loss of material was noted. Overall, the SSW and containment vessel liner are in very good condition with the coating intact and no signs of corrosion present. All welds inspected were in excellent conditions with no signs of cracking.

3.7.7.6 R21 Maintenance Rule Structural Inspections

Wetwell

The R21 Maintenance Rule Structural Inspection concluded the general condition of the wetwell is good. Carbon steel components that are not coated do have a light layer of surface corrosion on them. This has not changed over the years and has not resulted in an appreciable loss of material. The omega seal is stainless steel and is in excellent condition. The radial beams that support the drywell diaphragm slab were in good condition with all bolts installed and with very limited corrosion deposits. There was no appreciable loss of material on the bolts or nuts. The concrete columns which support these radial beams are coated and in good condition. The baseplate at the top of each does not exhibit a layer of corrosion. The downcomers are in good condition. Those downcomers that were previously modified do have a layer of general corrosion on surfaces above the point to where they are coated. The surfaces of the primary containment vessel above water (as seen from the platform just inside the access hatch) do have some small areas of general corrosion and these will be trended in future inspections.

Drywell

The R21 Maintenance Rule Structural Inspection concluded that the general condition of the drywell is good. Coatings on the PCV are in good condition. There were some concerns identified with potential blistering of the floor coatings under the coatings

inspection, but follow-up inspection showed the floor coatings to be well adhered to the diaphragm slab. The structural steel and connections were in good condition. No cracked welds or loose bolted connections were identified. Platforms and grating were in good condition. The greenish staining on the PCV between azimuth 240 and 270 at the 541' elevation has not changed. Much of the old insulation had been removed for outage activities but that which was still installed appeared in good condition and tightly installed. Inspection was performed from diaphragm slab at elevation 501' to the top of the sacrificial shield wall at elevation 568'. No areas of concern were identified.

3.8 Columbia Containment Modifications

3.8.1 Past Containment Modification

In 2003, the NRC revised 10 CFR 50.44, "Standards for Combustible Gas Control System for Nuclear Power Reactors." This revision eliminated the requirements for hydrogen recombiners and relaxed the requirements for hydrogen and oxygen monitoring. Columbia's Containment Atmosphere Control (CAC) system was a complex two-division system that performed these functions. However, it was no longer required based on the revised 10 CFR 50.44 standard and NRC's approval of Columbia's Licensing Amendment No. 189, Elimination of Requirements for Hydrogen Recombiners and Hydrogen/Oxygen Monitors Using the Consolidated Line Improvement Process (Reference 32) in 2005.

CAC system deactivation was implemented in two phases:

- Phase I – System disablement during refueling outage R-17 (May 2005)
- Phase II – Permanent system deactivation during refueling outage R-18 (May 2007)

Phase I isolated, disabled, and de-energized the CAC system. Phase II was an extension of Phase I and consisted of permanent deactivation of the CAC hydrogen recombiner skids, and permanent isolation of the CAC piping and electrical systems.

The Phase II modification mechanically isolated the CAC skid, permanently plugged CAC primary containment penetrations and isolated the CAC piping from the system interfaces with the Residual Heat Removal (RHR) system.

CAC/Containment Isolation

CAC supply and return piping was isolated from the primary containment atmosphere by plugging eight 6 inch diameter containment penetrations. Four penetrations are located inside the wetwell and four penetrations are located in the drywell. Each penetration had a plate welded to the open end, inside containment, then pressure tested to ensure primary containment isolation and integrity.

CAC Pipe System Interface Isolation

Piping interface connections were permanently isolated from the CAC system by cutting the pipe and installing a physical isolation barrier, either caps or welding a blind flange, between two systems to ensure no flow.

- CAC/residual heat removal RHR Loop A Isolation: RHR Loop A was blanked off using one blind flange installed in the vertical run of piping which connected CAC to the RHR drain.

- CAC/RHR Loop B Isolation: RHR Loop B was blanked off using one blind flange installed in the horizontal run of piping which connects CAC to the RHR drain.

The following CAC primary containment isolation valves are no longer required and are deactivated in place, de-energized and locked closed.

Drywell Penetrations

- Penetration X-96 (Containment Isolation Valves CAC-V-2 and CAC-FCV-2A)

- Penetration X-97 (Containment Isolation Valves CAC-V-15 and CAC-FCV-1B)

- Penetration X-98 (Containment Isolation Valves CAC-V-11 and CAC-FCV-2B)

- Penetration X-99 (Containment Isolation Valves CAC-V-6 and CAC-FCV-1A)

Wetwell Penetrations

- Penetration X-102 (Containment Isolation Valves CAC-V-4 and CAC-FCV-4A)

- Penetration X-103 (Containment Isolation Valves CAC-V-13 and CAC-FCV-4B)

- Penetration X-104 (Containment Isolation Valves CAC-V-17 and CAC-FCV-3B)

- Penetration X-105 (Containment Isolation Valves CAC-V-8 and CAC-FCV-3A)

The following piping interfacing connections to the CAC system are no longer required have been de-activated closed. Blind flanges CAC-BF-3A and CAC-BF-3B provide containment pressure boundaries in the lines outboard of the containment isolation valves.

Residual Heat Removal Penetrations

- Penetration X-117 (Containment Isolation Valve RHR-V-134A)
- Penetration X-118 (Containment Isolation Valve RHR-V-134B)

Post-maintenance testing was performed on each of the retired penetrations following installation of the welded plate. A local pressure test was performed to P_a (38.5 to 39 psig) and an inspection of each penetration plug weld was performed to ASME Code VT-2 visual examination requirements during the 10 minute hold time. Each plug weld was verified to be satisfactory except the plug weld on X97 failed its VT-2 exam. However, the 2200 sccm leak rate was considered insignificant when applied toward the 0.6 La startup limit of 72,922 sccm. These plug welds were also verified as satisfactory during the Type A test performed during the R19 refueling outage in June 2009.

3.8.2 Refueling Outage 23 Containment Modification

On March 19, 2013, the NRC Commissioners directed the staff per Staff Requirements Memorandum (SRM) for SECY-12-0157 (Reference 33) to require licensees with Mark I and Mark II containments to "upgrade or replace the reliable hardened vents required by Order EA-12-050 (Reference 34) with a containment venting system designed and installed to remain functional during severe accident conditions." In response to this order, Columbia is installing a reliable hardened containment venting system during refueling outage 23 (R23) to satisfy the regulatory requirements described in Phase 1 of NRC Order EA-13-109.

The Hardened Containment Vent (HCV) System will provide Columbia with a reliable, severe accident capable vent which will remove decay heat to maintain containment pressure within acceptable limits in the event of a severe accident. Implementation of the HCV will reduce the probability of containment failure during severe accident sequences that may result in loss of active containment heat removal capability or Extended Loss of Alternating Current (AC) Power (ELAP).

HCV Interface with Containment

The HCV system from the wetwell primary containment penetration X-58 up to and including the Primary Containment Isolation Valves (PCIVs) HCV-V-1 and HCV-V-2, and drain valves HCV-V-800/1, and HCV-V-800/2 will be part of the Primary Containment boundary.

Both HCV-V-1 and HCV-V-2 are 16 inch triple offset butterfly valves. The drain valves HCV-V-800/1 and HCV-V-800/2 are ¾ inch globe valves. Penetration X-58 is an existing 12 inch diameter primary containment penetration.

Leak rate testing of the PCIVs is required as part of the post modification testing. Testing will be performed in accordance with the existing Primary Containment Leakage Rate Testing Program.

3.9 License Renewal Aging Management

By letter dated January 19, 2010, Energy Northwest submitted a License Renewal Application in accordance with 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants" (Reference 26) requesting renewal of Facility Operating License NPF-21 for a period of 20 years beyond the current license period ending December 23, 2023. In February 2012, the NRC issued the SER related to the license renewal of Columbia (Reference 17). The following programs, which are part of the supporting basis of this LAR, are also Aging Management Programs at Columbia.

3.9.1 Aging Management Programs

Appendix J Program

The Appendix J Program is an existing monitoring program that detects degradation of the Primary Containment and systems penetrating the Primary Containment, which are the containment shell and primary containment penetrations including (but not limited to) the personnel airlock, equipment hatch, control rod drive hatch, and drywell head. The Appendix J Program provides assurance that leakage from the Primary Containment will not exceed maximum values for containment leakage.

Inservice Inspection Program – IWE

The Inservice Inspection Program – IWE is an existing program that establishes responsibilities and requirements for conducting IWE inspections as required by 10 CFR 50.55a. The ISI Program – IWE includes visual examination of all accessible surface areas of the steel containment and its integral attachments, and containment pressure-retaining bolting in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWE.

The inservice examinations conducted throughout the service life of Columbia will comply with the requirements of the ASME Section XI Edition and Addenda incorporated by reference in 10 CFR 50.55a(b) twelve months prior to the start of the inspection interval, subject to prior approval of the edition and addenda by the NRC. This is consistent with NRC statements of consideration for 10 CFR 54 associated with the adoption of new editions and addenda of the ASME Code in 10 CFR 50.55a.

Structures Monitoring Program

The Structures Monitoring Program manages age-related degradation of plant structures and structural components within its scope to ensure that each structure or structural component retains the ability to perform its intended function. Aging effects are detected by visual inspection of external surfaces prior to the loss of the structure's or component's intended function.

Service Level 1 Protective Coatings Program

The Service Level 1 Protective Coating Program monitors the performance of Service Level 1 coatings inside containment through periodic coating examinations, condition assessments, and remedial actions, including repair or testing. The program establishes roles, responsibilities, controls and deliverables for the Service Level 1 Protective Coatings Program. This program also ensures the DBA analysis limits with regard to coating will not be exceeded for the suction strainers.

3.9.2 Aging Management Commitments

Due to the possibility of containment shell degradation from corrosion induced by a moist environment in the sand pocket region, Columbia committed in the License Renewal Application to continue to monitor humidity levels in this region and implemented a procedure to survey the relative humidity of air drawn from within the containment annulus sand pocket region. Acceptance criteria for minimum dry bulb temperature and maximum relative humidity of air in the sand pocket region have been established.

Review of past inspection results revealed that inspections performed were satisfactory and surveillances since mid-1988 indicate that no water was detected, and there is no evidence of leakage into the sand pocket region. The measurement of sand pocket area humidity provides assurance that water is not accumulating in the sand pocket area, which could cause corrosion of the outer surface of the containment shell. Past data shows the worst-case dew point temperature of the sand pocket air was about 54 degrees F. The temperature of the containment shell in the sand pocket area is essentially the same temperature as the suppression pool water. The suppression pool water temperature is normally maintained above 54 degrees F.

Furthermore, the humidity in the sand pocket region is measured prior to reactor cavity flood-up and after the reactor cavity drain-down to ensure water has not been introduced into the sand pocket area during refueling activities. In addition, the sand pocket drains are checked monthly (28-day frequency) for the presence of water. To date, no water has been documented as a result of drain line surveillance; however, if water is discovered during future inspections, it will be addressed in the Energy Northwest Corrective Action Program.

Energy Northwest committed to perform a borescope inspection of the containment sand pocket drain lines to confirm the absence of clogged drain lines and existence of a flow path existed for identification of any potential leakage into the sand pocket region. The commitment had a due date of December 31, 2015. The borescope inspections of each drain line (eight total) were performed in April 2014. All eight drain lines were confirmed to be unclogged with a flow path for any potential leakage into the sand pocket region to be identified through opening of the valve at the end of each drain line. However, there was some loose sand found in the drain lines associated with two of the valves. This sand was loose and would not have prevented the flow of any potential water through the drain line. Work requests were generated to remove this sand and leave a sand-free drain line and prevent any potential for future clogging of the associated valves. All actions were performed necessary to satisfying the commitment prior to the due date.

3.10 NRC SER Limitations and Conditions

3.10.1 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 3.10.1-1 were satisfied:

Table 3.10.1-1
NEI 94-01, Revision 2-A, Limitations and Conditions

Limitation/Condition (From Section 4.0 of SER)	Energy Northwest 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.)	Columbia 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 Sections 3.6.2 and 3.6.3 of this submittal.
The licensee addresses the areas of the containment structure potentially subjected to degradation. (Refer to SE Section 3.1.3.)	Reference Section 3.6.2 of this submittal.

Table 3.10.1-1 NEI 94-01, Revision 2-A, Limitations and Conditions	
Limitation/Condition (From Section 4.0 of SER)	**Energy Northwest Response**
The licensee addresses any tests and inspections performed following major modifications to the containment structure, as applicable. (Refer to SE Section 3.1.4.)	Columbia will be adding a hardened containment vent system as required by NRC Order EA-13-109 during R23. Both past and future containment modifications are discussed in Section 3.8
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.)	Energy Northwest will follow the requirements of NEI 94-01 Revision 3-A, Section 9.1. This requirement has remained unchanged from Revision 2-A to Revision 3-A of NEI 94-01. In accordance with the requirements of NEI 94-01 Revision 2-A, SER Section 3.1.1.2, Energy Northwest 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 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. Columbia was not licensed under 10 CFR 52.

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

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

Topical Report Condition 1

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

Response to Condition 1

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

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

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

- ISSUE 3 - Use of the allowed 9-month extension for eligible Type C valves is only authorized for non-routine emergent conditions 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 Minimum Pathway Leak Rate (MNPLR) summation value, as adjusted to include the estimate of applicable Type C leakage understatement, and its regulatory limit of 0.60 L_a.

Response to Condition 1, ISSUE 2

When the potential leakage understatement adjusted Type B and C MNPLR total is greater than the Columbia Maintenance Rule leakage summation limit of 0.45 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 Columbia 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

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

Topical Report Condition 2

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

When routinely scheduling any LLRT valve interval beyond 60-months and up to 75-months, the primary containment leakage rate testing program trending or monitoring must include an estimate of the amount of understatement in the Type B and C total 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 two (2) separate issues that are required to be addressed as follows:

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

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

Response to Condition 2, ISSUE 1

The change in going from a 60-month extended test interval for Type C tested components to a 75-month interval, as authorized under NEI 94-01, Revision 3-A, represents an increase of 25% in the LLRT periodicity. As such, Energy Northwest will conservatively apply a potential leakage understatement adjustment factor of 1.25 to the actual As-Left leak rate, which will increase the As-Left leakage total for each Type C component currently on greater than a 60-month test interval up to the 75-month extended test interval. This will result in a combined conservative Type C total for all 75-month LLRTs being "carried forward" and will be included whenever the total leakage summation is required to be updated (either while on line or following an outage).

When the potential leakage understatement adjusted leak rate total for those Type C components being tested on greater than a 60-month test interval up to the 75-month extended test interval is summed with the non-adjusted total of those Type C components being tested at less than or equal to a 60-month test interval, and the total of the Type B tested components, if the MNPLR is greater than the Columbia Maintenance Rule leakage summation limit of 0.45 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 Columbia leakage limit. The corrective action plan shall focus on those components which have contributed the most to the increase in the leakage summation value and what manner of timely corrective action, as

deemed appropriate, best focuses on the prevention of future component leakage performance issues.

Response to Condition 2, ISSUE 2

If the potential leakage understatement adjusted leak rate MNPLR is less than the Columbia Maintenance Rule leakage summation limit of 0.45 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 Columbia, 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 Columbia an adverse trend is defined as three (3) 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.

3.11 Conclusion

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

Based on the previous ILRTs conducted at Columbia, it may be concluded that the permanent extension of the containment ILRT interval from 10 to 15 years represents minimal risk to increased leakage. The risk is minimized by continued Type B and Type C testing performed in accordance with Option B of 10 CFR 50, Appendix J, Drywell Inspections and the overlapping inspection activities performed as part of the following Columbia inspection programs:

- Inservice Inspection Program IWE
- Containment Maintenance Rule Inspections
- Containment Inspections per TS SR 3.6.1.1.1
- Service Level 1 Coatings Program.

This experience is supplemented by risk analysis studies, including the Columbia risk analysis provided in Enclosure 4 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 since it represents only a small change in the Columbia 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 (Reference 18) , 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 states that Type A ILRT intervals of up to 15 years are allowed by this guideline. The Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals, EPRI Report 1018243 (formerly TR-1009325, Revision 2) indicates that, in general, the risk impact associated with ILRT interval extensions for intervals up to 15 years is small. However, plant-specific confirmatory analyses are required.

The NRC staff reviewed NEI TR 94-01, Revision 2, and EPRI Report No. 1009325, Revision 2. For NEI TR 94-01, Revision 2, the NRC staff determined that it described an acceptable approach for implementing the optional performance-based requirements of Option B to 10 CFR 50, Appendix J. This guidance includes provisions for extending Type A ILRT intervals up to 15 years and incorporates the regulatory positions stated in RG 1.163 (Reference 1). The NRC staff finds that the Type A testing methodology as described in ANSI/ANS-56.8-2002 (Reference 14), and the modified testing frequencies recommended by NEI TR 94-01, Revision 2, serve to ensure continued leakage integrity of the containment structure. Type B and Type C testing ensures that individual penetrations are essentially leak tight. In addition, aggregate Type B and Type C leakage rates support the leakage tightness of primary containment by minimizing potential leakage paths.

For EPRI Report No. 1009325, Revision 2 (Reference 18), 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 1.177 (Reference 19) and RG 1.174 (Reference 4). The NRC staff, therefore, found that this guidance was acceptable for referencing by licensees proposing to amend their TS in regards to containment leakage rate testing, subject to the limitations and conditions noted in Section 4.2 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 conditions and limitations summarized in Section 4.0 of the associated SE. This guidance included provisions for extending Type C LLRT intervals up to 75 months. Type C testing ensures that individual CIVs are essentially 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 regards to containment leakage rate testing. Any applicant may reference NEI TR 94-01, Revision 3, as modified by the associated SER and approved by the NRC, and the conditions and limitations specified in NEI 94-01, Revision 2-A, dated October 2008, in a licensing action to satisfy the requirements of Option B to 10 CFR 50, Appendix J.

4.2 Precedent

This 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:

- Surry Power Station, Unit 1 (Reference 20)
- Donald C. Cook Nuclear Plant, Unit 1 (Reference 21)
- Beaver Valley Power Station, Unit Nos. 1 and 2 (Reference 22)
- Calvert Cliffs Nuclear Power Plant, Unit Nos. 1 and 2 (Reference 23)
- Peach Bottom Atomic Power Station, Units 2 and 3 (Reference 24)
- Comanche Peak Nuclear Power Plant, Units 1 and 2 (Reference 25)
- James A. Fitzpatrick Nuclear Power Plant (Reference 39)
- Catawba Nuclear Station, Units 1 and 2 (Reference 40)
- H.B. Robinson Steam Electric Plant, Unit No. 2 (Reference 41).

4.3 No Significant Hazards Consideration

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

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

Response: No.

The proposed activities involve the revision of Columbia Generating Station (Columbia) Technical Specification (TS) 5.5.12 to allow the extension of the Type A containment test interval to 15 years, and the extension of the Type C test interval to 75 months. The current Type A test interval of 120 months (10 years) would be extended on a permanent basis to no longer than 15 years from the last Type A test. The current Type C test interval of 60 months for selected components would be extended on a performance basis to no longer than 75 months. Extensions of up to nine months (total maximum interval of 84 months for Type C tests) are permissible only for non-routine emergent conditions.

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

The change in Type A test frequency to once-per-fifteen-years, measured as an increase to the total integrated plant risk for those accident sequences influenced by Type A testing, is 2.77E-4 person-rem/yr (a 0.00761% increase). EPRI Report No. 1009, Revision 2-A states that a very small population dose is defined as an increase of less than 1.0 person-rem per year or less than 1 percent of the total population dose, whichever is less restrictive for the risk impact assessment of the extended ILRT intervals. Moreover, the risk impact when compared to other severe accident risks is negligible. Therefore, the proposed extension does not involve a significant increase in the probability of an accident previously evaluated.

In addition, as documented in NUREG-1493, “Performance-Based Containment Leak-Test Program,” dated January 1995, Types B and C tests have identified a very large percentage of containment leakage paths, and the percentage of containment leakage paths that are detected only by Type A testing is very small. The Columbia 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. Local leak rate test 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 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 two exceptions previously granted. The first exception allowed a one-time extension of the ILRT test frequency for Columbia. This exception was for an activity that has already taken place; therefore, this deletion is solely an administrative action that does not result in any change in how Columbia is operated. The second exemption to compensate for flow meter inaccuracies in excess of those specified in the American National Standards Institute (ANSI) / American Nuclear Society (ANS) ANSI/ANS 56.8-1994 will be deleted as new test equipment has been acquired with accuracies within the tolerances specified in ANSI/ANS 56.8-1994 and 2002.

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 the TS 5.5.12, "Primary Containment Leakage Rate Testing Program," involves the extension of the Columbia Type A containment test interval to 15 years and the extension of the Type C test interval to 75 months. The containment and the testing requirements to periodically demonstrate the integrity of the containment exist to ensure the plant's ability to mitigate the consequences of an accident.

The proposed change does not involve a physical modification to the plant (i.e., no new or different type of equipment will be installed) nor does it alter the design, configuration, or change the manner in which the plant is operated or controlled beyond the standard functional capabilities of the equipment.

The proposed amendment also deletes two exceptions previously granted. The first exception granted under TS Amendment No. 191 allowed a one-time extension of the ILRT test frequency for Columbia. This exception was for an activity that has already occurred; therefore, this deletion is solely an administrative action that does not result in any change in how Columbia is operated. The second exemption which was originally granted via Amendment No. 144 to compensate for flow meter inaccuracies in excess of those specified in ANSI/ANS 56.8-1994, will be deleted as new test equipment has been acquired with accuracies within the tolerances specified in ANSI/ANS 56.8-1994 and 2002. These changes to the exceptions in TS 5.5.12 are administrative in nature and do not create the possibility of a new or different kind of accident from any previously evaluated.

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

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

Response: No.

The proposed amendment to TS 5.5.12 involves the extension of the Columbia Type A containment test interval to 15 years and the extension of the Type C test interval to 75 months for selected components. This amendment does not alter the manner in which safety limits, limiting safety system set points, or limiting conditions for operation are determined. The specific requirements and conditions of the TS Containment Leak Rate Testing Program exist to ensure that the degree of containment structural integrity and leak-tightness that is considered in the plant safety analysis is maintained. The overall containment leak rate limit specified by TS is maintained.

The proposed change involves the extension of the interval between Type A containment leak rate tests and Type C tests for Columbia. The proposed surveillance interval extension is bounded by the 15-year ILRT interval and the 75-month Type C test interval currently authorized within NEI 94-01, Revision 3-A. Industry experience supports the conclusion 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 Type A, B, and C containment leakage tests specified in applicable codes and standards would continue to be met, with the acceptance of this proposed change, since these are not affected by changes to the Type A and Type C test intervals.

The proposed amendment also deletes exceptions previously granted to allow one time extension of the ILRT test frequency for Columbia. This exception was for an activity that has taken place; therefore, the deletion is solely an administrative action and does not change how Columbia is operated and maintained. Thus, there is no reduction in any margin of safety.

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

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

4.4 Conclusion

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

5.0 ENVIRONMENTAL CONSIDERATION

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

6.0 REFERENCES

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

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

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

4. Regulatory Guide 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

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

6. Regulatory Guide 1.1, "Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps (Safety Guide 1)," November 1970

7. NEI 94-01, Revision 0, “Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J,” July 1995

8. NUREG-1493, “Performance-Based Containment Leak-Test Program,” January 1995

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

10. Letter to J. C. Butler (NEI) from M. J. Maxin (NRC), "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 50, Appendix J' and Electric Power Research Institute (EPRI) Report No. 1009325, Revision 2, August 2007, 'Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals' (TAC No. MC9663)," dated June 25, 2008, (ML081140105)

11. Letter to B. Bradley (NEI) from S. Bahadur (NRC), "Final Safety Evaluation of Nuclear Energy Institute (NEI) Report 94-01, Revision 3, Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J (TAC No. ME2164)," dated June 8, 2012, (ML121030286)

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13. ANSI/ANS 56.8-1994, “Containment System Leakage Testing Requirements,” dated August 4, 1994

14. ANSI/ANS 56.8-2002, “Containment System Leakage Testing Requirements,” dated November 27, 2002

15. Letter to J.V. Parrish (Energy Northwest) from B. Benney (NRC), “Columbia Generating Station – Issuance of Amendment Re: One-Time Extension of Appendix J Type A Integrated Leakage Rate Test Interval (TAC No. MC3942), dated April 12, 2005 (ML050620553) [Amendment No. 191]

16. Letter to J.V. Parrish (Energy Northwest) from C.F. Lyon (NRC), “Columbia Generating Station – Issuance of Amendment Re: Suppression Chamber to Drywell Vacuum Breakers and Drywell to Suppression Chamber Bypass Leakage Test (TAC No. MD1225),” dated February 9, 2007 (ML070300018) [Amendment No. 201]

17. NUREG-2123, USNRC Safety Evaluation Report Related to the License Renewal of Columbia Generating Station, Volumes 1 and 2 Docket Number 50-397, May 2012 (ML12139A300 and ML12139A302)

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

19. Regulatory Guide 1.177, Revision 1, "An Approach for Plant-Specific, Risk-Informed Decision Making: Technical Specifications," May 2011

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

21. Letter to L. J. Weber from A. W. Dietrich (NRC), "Donald C. Cook Nuclear Plant, Units 1 and 2 - Issuance of Amendments Re: Containment Leakage Rate Testing Program (TAC NOS. MF3568 and MF 3569)," dated March 30, 2015 (ML15072A264)

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

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24. Letter to B. C. Hanson from R. B. Ennis (NRC), "Peach Bottom Atomic Power Station, Units 2 and 3 - Issuance of Amendments Re: Extension of Type A and

Type C Leak Rate Test Frequencies (TAC NOS. MF5172 AND MF5173)," dated September 8, 2015 (ML15196A559)

25. Letter to R. Flores from B. K. Singal (NRC), "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 (ML15309A073)

26. Letter to NRC from W.S. Oxenford (Energy Northwest), "Columbia Generating Station, Docket No. 50-397 License Renewal Application," dated January 19, 2010 (ML100250656)

27. Letter from E. Gettys (NRC) to W.S. Oxenford (Energy Northwest), "Request for Additional Information for the Review of the Columbia Generating Station, License Renewal Application Concerning Structures," dated July 7, 2010 (ML101730468)

28. Letter from S.K. Gambhir (Energy Northwest) to USNRC, "Columbia Generating Station, Docket No. 50-397 Response to Request for Additional Information License Renewal Application," dated September 3, 2010. (ML102520049)

29. 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, dated November 2001.

30. Letter from C.H. Cruse (Calvert Cliffs Nuclear Power Plant) to NRC Document Control Desk, "Calvert Cliffs Nuclear Power Plant Unit 1; Docket No. 50-317, Response to Request for Additional Information Concerning the License Amendment Request for a One-Time Integrated Leakage Rate Test Extension," dated March 27, 2002 (ML02090100)

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

32. Letter from B.J. Benney (NRC) to J.V. Parrish (Energy Northwest), "Columbia Generating Station – Issuance of Amendment Re: Elimination of Requirements for Hydrogen Recombiners and Hydrogen/Oxygen Monitors Using the Consolidated Line Item Improvement Process (TAC No. MC4444)," dated March 3, 2005 (ML0505620277)

33. SECY-12-0157, "Consideration of Additional Requirements for Containment Venting Systems for Boiling Water Reactors with Mark I and Mark II Containments," dated November 26, 2012 (ML12325A704).

34. NRC Order EA-12-050, Order Modifying Licenses with Regard to Reliable Hardened Containment Vents, dated March 9, 2012 (ML12055A696).

35. NRC Order EA-13-109, "Issuance of Order to Modify Licenses with Regard to Reliable Hardened Containment Vents Capable of Operation under Severe Accident Conditions," dated June 6, 2013 (ML13143A321).

36. Letter to M. E. Reddemann (Energy Northwest) from L. J. Klos (NRC), "Columbia Generating Station – Issuance of Amendment RE: Adoption of Technical Specification Task Force Traveler TSTF-425, Revision 3 (CAC No. MF6042)," dated November 3, 2016 (ML16253A025)

37. Energy Northwest Docket No. 50.397, Columbia Generating Station Amendment to Renewed Facility Operating License, Amendment No. 238 License No. NPF-21, United States Nuclear Regulatory Commission, ADAMS Accession No. ML16253A025, November 3, 2016.

38. Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 238 to Renewed Facility Operating License No. NPF-21 Energy Northwest Columbia Generating Station Docket No. 50-397, United States Nuclear Regulatory Commission, ADAMS Accession No. ML16253A025, November 3, 2016.

39. Letter to Site Vice President James A. Fitzpatrick Nuclear Power Plant from D.L. Render (NRC), "James A. Fitzpatrick Nuclear Power Plant – Issuance of Amendment Re: Revision of Technical Specification 5.5.6 for Extension of Type A and Type C Leak Rate Test Frequencies (CAC No. MF8305)," dated January 24, 2017 (ML17009A372).

40. Letter to K. Henderson (Duke Energy) from M.D. Orenak (NRC), "Catawba Nuclear Station, Units 1 and 2 – Issuance of Amendments Regarding Extension of the Containment Integrated Leak Rate Test Intervals (CAC Nos. MF7265 and MF7266)," dated September 12, 2016 (ML16229A113).

41. Letter to R.M. Glover (Duke Energy) from D.J. Galvin (NRC), "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.

42. Severe Accident Mitigation Alternatives (SAMA), Revision 7.1 Sensitivity Analysis, MSE-EJJ-10-008, Revision 6, April 13, 2011.

43. Letter from R.J. Barrett (Entergy) to U.S. Nuclear Regulatory Commission, IPN-01-007, dated January 18, 2001.

44. Letter to M. Kansler (Entergy) from G. F. Wunder (NRC), "Indian Point Nuclear Generating Unit No. 3 – Issuance of Amendment Re: Frequency of Performance-Based Leakage Rate Testing (TAC No. MB0178)," dated April 17, 2001 (ML011020315)

45. Release of the CGS Model Version 7.2 PRA Model, PSA-1-SM-0001, dated October 2014

46. PSA-Rev-7.2.1, PSA Revision 7.2.1, dated June 2016

47. Bayesian Update of CGS PSA Data, PSA-2-DA-0002, Revision 4, 2010

Enclosure 2

Proposed Columbia Technical Specification Changes (Mark-Up)

5.5 Programs and Manuals

5.5.11 Safety Function Determination Program (SFDP) (continued)

a. The SFDP shall contain the following:

1. Provisions for cross division checks to ensure a loss of the capability to perform the safety function assumed in the accident analysis does not go undetected;

2. Provisions for ensuring the plant is maintained in a safe condition if a loss of function condition exists;

3. Provisions to ensure that an inoperable supported system's Completion Time is not inappropriately extended as a result of multiple support system inoperabilities; and

4. Other appropriate limitations and remedial or compensatory actions.

b. A loss of safety function exists when, assuming no concurrent single failure, a safety function assumed in the accident analysis cannot be performed. For the purpose of this program, a loss of safety function may exist when a support system is inoperable, and:

1. A required system redundant to system(s) supported by the inoperable support system is also inoperable; or

2. A required system redundant to system(s) in turn supported by the inoperable supported system is also inoperable; or

3. A required system redundant to support system(s) for the supported systems described in b.1 and b.2 above is also inoperable.

c. The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

5.5.12 Primary Containment Leakage Rate Testing Program

The Primary Containment Leakage Rate Testing Program shall establish 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 accordance with the guidelines contained in NEI 94-01, "Industry Guideline for Implementing Performance-Based option of 10 CFR Part 50, Appendix J," Revision 3-A, dated July 2012, and the conditions and limitations specified in NEI 94-01, Revision 2-A, dated October 2008. ~~Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995, as modified by the following exceptions: The next Type A test~~

5.5 Programs and Manuals

5.5.12 Primary Containment Leakage Rate Testing Program (continued)

~~performed after the July 20, 1994, Type A test shall be performed no later than July 20, 2009, and compensation for flow meter inaccuracies in excess of those specified in ANSI/ANS 56.8-1994 will be accomplished by increasing the actual instrument reading by the amount of the full scale inaccuracy when assessing the effect of local leak rates against the criteria established in Specification 5.5.12.a.~~

The peak calculated primary containment internal pressure for the design basis loss of coolant accident, P_a, is 38 psig.

The maximum allowable primary containment leakage rate, L_a, at P_a, shall be 0.5% of primary containment air weight per day.

Leakage rate acceptance criteria are:

a. Primary containment 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 Type B and Type C tests (except for main steam isolation valves) and < 0.75 L_a for Type A tests;

b. Primary containment air lock testing acceptance criteria are:

   1. Overall primary containment air lock leakage rate is ≤ 0.05 L_a when tested at ≥ P_a; and

   2. For each door, leakage rate is ≤ 0.025 L_a when pressurized to ≥ 10 psig.

The provisions of SR 3.0.3 are applicable to the Primary Containment Leakage Rate Testing Program.

5.5.13 Battery Monitoring and Maintenance Program

This Program provides for restoration and maintenance, which includes the following:

a. Actions to restore battery cells with float voltage < 2.13 V; and

b. Actions to equalize and test battery cells that had been discovered with electrolyte level below the top of the plates; and

c. Actions to verify that the remaining cells are ≥ 2.07 V when a cell or cells have been found to be < 2.13 V.

Enclosure 3

Proposed Columbia Technical Specification Changes (Clean)

5.5 Programs and Manuals

5.5.11 Safety Function Determination Program (SFDP) (continued)

a. The SFDP shall contain the following:

1. Provisions for cross division checks to ensure a loss of the capability to perform the safety function assumed in the accident analysis does not go undetected;

2. Provisions for ensuring the plant is maintained in a safe condition if a loss of function condition exists;

3. Provisions to ensure that an inoperable supported system's Completion Time is not inappropriately extended as a result of multiple support system inoperabilities; and

4. Other appropriate limitations and remedial or compensatory actions.

b. A loss of safety function exists when, assuming no concurrent single failure, a safety function assumed in the accident analysis cannot be performed. For the purpose of this program, a loss of safety function may exist when a support system is inoperable, and:

1. A required system redundant to system(s) supported by the inoperable support system is also inoperable; or

2. A required system redundant to system(s) in turn supported by the inoperable supported system is also inoperable; or

3. A required system redundant to support system(s) for the supported systems described in b.1 and b.2 above is also inoperable.

c. The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

5.5.12 Primary Containment Leakage Rate Testing Program

The Primary Containment Leakage Rate Testing Program shall establish 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 accordance with the guidelines contained in NEI 94-01, "Industry Guideline for Implementing Performance-Based option of 10 CFR Part 50, Appendix J," Revision 3-A, dated July 2012, and the conditions and limitations specified in NEI 94-01, Revision 2-A, dated October 2008.

5.5 Programs and Manuals

5.5.12 Primary Containment Leakage Rate Testing Program (continued)

The peak calculated primary containment internal pressure for the design basis loss of coolant accident, P_a, is 38 psig.

The maximum allowable primary containment leakage rate, L_a, at P_a, shall be 0.5% of primary containment air weight per day.

Leakage rate acceptance criteria are:

a. Primary containment 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 Type B and Type C tests (except for main steam isolation valves) and < 0.75 L_a for Type A tests;

b. Primary containment air lock testing acceptance criteria are:

   1. Overall primary containment air lock leakage rate is ≤ 0.05 L_a when tested at ≥ P_a; and

   2. For each door, leakage rate is ≤ 0.025 L_a when pressurized to ≥ 10 psig.

The provisions of SR 3.0.3 are applicable to the Primary Containment Leakage Rate Testing Program.

5.5.13 Battery Monitoring and Maintenance Program

This Program provides for restoration and maintenance, which includes the following:

a. Actions to restore battery cells with float voltage < 2.13 V; and

b. Actions to equalize and test battery cells that had been discovered with electrolyte level below the top of the plates; and

c. Actions to verify that the remaining cells are ≥ 2.07 V when a cell or cells have been found to be < 2.13 V.

Enclosure 4

Evaluation of Risk Significance of Permanent ILRT Extension for Columbia Generating Station

MARACOR

A division of ENERCON

Evaluation of Risk Significance of Permanent ILRT Extension

Columbia Generating Station

Revision 0

Prepared by: 3/14/17

Joseph Lavelline, Maracor

Reviewed by: 3/14/17

Blake Smith, Energy Northwest

Forward

The purpose of this analysis is to provide a risk assessment of extending the currently allowed containment Type A integrated leak rate test (ILRT) to a permanent interval of fifteen years. The information presented in and the format of this analysis is derived from the template contained in Appendix H of EPRI 1009325, Revision 2-A (Reference 26). The main purpose of the template in Reference 26 is to illustrate the type of information that should be included in a plant-specific confirmation of risk impact associated with the extension of ILRT intervals; this template has been followed for the development of this report.

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1. Analysis Overview

1.0 Purpose

The purpose of this analysis is to provide a risk assessment of extending the currently allowed containment Type A integrated leak rate test (ILRT) to a permanent interval of fifteen years. The extension would allow for substantial cost savings as the ILRT could be deferred for additional scheduled refueling outages for the Columbia Generating Station (CGS) Nuclear Power Plant. The risk assessment follows the guidelines from:

1. NEI 94-01, Revision 3-A (Reference 1), the methodology used in EPRI TR-104285 (Reference 2).
2. The NEI document *Interim Guidance for Performing Risk Impact Assessments In Support of One-Time Extensions for Containment Integrated Leakage Rate Test Surveillance Intervals* (Reference 3).
3. The NRC regulatory guidance on the use of Probabilistic Risk Assessment (PRA) as stated in Regulatory Guide 1.200 (Reference 36) as applied to ILRT interval extensions.
4. Risk insights in support of a request for a change of the plant's licensing basis as outlined in Regulatory Guide (RG) 1.174 (Reference 4).
5. 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).
6. The methodology used in EPRI 1009325, Revision 2-A (Reference 26).

1.1 Background

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

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 1) states that NUREG-1493, "Performance-Based Containment Leak Test Program," September 1995 (Reference 6), provides the technical basis to support rulemaking to revise leakage rate testing requirements contained in Option B to Appendix J. The basis consisted of qualitative and quantitative assessments of the risk impact (in terms of increased public dose) associated with a range of extended leakage rate test intervals. To supplement the NRC's rulemaking basis, NEI undertook a similar study. The results of that study are documented in Electric Power Research Institute (EPRI) Research Project Report TR- 104285, "Risk Impact Assessment of Revised Containment Leak Rate Testing Intervals." The NRC report on performance-based leak testing, NUREG-1493, analyzed the effects of containment

leakage on the health and safety of the public and the benefits realized from the containment leak rate testing. In that analysis, it was determined for a representative PWR plant (i.e., Surry), that containment isolation failures contribute less than 0.1 percent 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 the CGS Nuclear Power Plant.

The Guidance provided in Appendix H of EPRI Report No. 1009325, Revision 2-A, *Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals* (Reference 26) for performing risk impact assessments in support of ILRT extensions builds on the EPRI Risk Assessment methodology, EPRI TR-104285. This methodology is followed to determine the appropriate risk information for use in evaluating the impact of the proposed ILRT changes.

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

1.2 Acceptance Criteria

The acceptance guidelines in RG 1.174 are used to assess the acceptability of this permanent extension of the Type A test interval beyond that established during the Option B rulemaking of Appendix J. RG 1.174 defines very small changes in the risk-acceptance guidelines as increases in core damage frequency (CDF) less than 10^{-6} per reactor year and increases in large early release frequency (LERF) less than 10^{-7} per reactor year. 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, an assessment of the increase in the conditional containment failure probability (CCFP) helps to ensure that the defense-in-depth philosophy is maintained.

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 advanced light water designs. Given these perspectives, a change in the CCFP of up to 1.5% is assumed to be small.

In addition, the total annual risk (person rem/yr 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) indicate a range of incremental increases in population dose that have been accepted by the NRC (Reference 11). The range of incremental population dose increases is from ≤.0.01 to 0.2 person-rem/yr 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 very 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.

For those plants that credit containment overpressure for the mitigation of design basis accidents, a brief description of whether overpressure is required should be included in this section. In addition, if overpressure is included in the assessment, other risk metrics such as CDF should be described and reported. However, CGS does not credit containment overpressure in the plant design basis or in the PRA; therefore, containment overpressure is not analyzed in this assessment.

1.3 Abbreviations

The following is a list of acronyms which are used widely throughout this document. These acronyms may be used in the text of this document without an accompanying definition.

1) ADS Automatic Depressurization System
2) AONL Always or Never LERF
3) AOT Allowed Outage Time
4) AOV Air-operated Valve
5) ASME American Society of Mechanical Engineers
6) ATWS Anticipated Transient Without Scram
7) BE Basic Event
8) BOC Break Outside Containment
9) BWR Boiling Water Reactor
10) CCII Capability Category II
11) CCDP Conditional Core Damage Probability
12) CCFP Conditional Containment Failure Probability
13) CCF Common Cause Factor
14) CD Core Damage
15) CDF Core Damage Frequency
16) CET Containment Event Tree

17) CGS Columbia Generating Station
18) CI Containment Intact
19) CIA Control Instrument Air
20) CLERP Conditional Large Early Release Probability
21) CLRT Containment Leak Rate Test
22) CRD Control Rod Drive
23) DHR Decay Heat Removal
24) DW Drywell
25) ECCS Emergency Core Cooling System
26) EOP Emergency Operating Procedure
27) EPIX Equipment Performance and Information Exchange
28) EPRI Electric Power Research Institute
29) F-V Fussell-Vesely
30) F&O Findings and Observations
31) FPRA Fire PRA
32) FV Fussell-Vesely
33) H/E High/Early Release
34) H/I High Intermediate Release
35) HFE Human Failure Event
36) HEP Human Error Probability
37) HPCS High Pressure Core Spray
38) HRA Human Reliability Analysis
39) ID Inner Diameter
40) ILRT Integrated Leak Rate Test
41) IP3 Indian Point 3
42) IPE Individual Plant Examination
43) IPEEE Individual Plant Examination for External Events
44) ISI Inservice Inspection
45) ISLOCA Interfacing System Loss of Coolant Accident
46) IST Inservice Testing
47) L/E Low/Early Release
48) L/I Low Intermediate Release
49) LERF Large Early Release Frequency
50) LCO Limiting Condition(s) for Operation
51) LL Low-Low
52) LL/E Low-Low/Early Release
53) LL/I Low-Low Intermediate Release
54) LLRT Local Leakage Rate Test
55) LOCA Loss of Coolant Accident
56) M/E Medium/Early Release
57) M/I Medium Intermediate Release
58) MCUB Minimum-Cutset Upper Bound
59) MOV Motor-operated valve
60) MR Maintenance Rule
61) MSIV Manual Safety Injection Valve
62) NEI Nuclear Energy Institute

63) NRC Nuclear Regulatory Commission
64) OD Outer Diameter
65) ORNL Oak Ridge National Laboratory
66) P&IDs Piping and instrumentation drawings
67) PCPL Primary Containment Pressure Limit
68) PCS Power Conversion System
69) PDS Plant Damage State
70) PRA Probabilistic Risk Assessment
71) PSA Probabilistic Safety Assessment
72) PSIA Pounds per Square Inch Absolute
73) PSID Pounds per Square Inch Differential
74) PSIG Pounds per Square Inch Gauge
75) PWR Pressurized Water Reactor
76) QU Quantification
77) RAI Request for Additional Information
78) RAW Risk Achievement Worth
79) RCIC Reactor Core Isolation Cooling
80) RG Regulatory Guide
81) RFW Reactor Feedwater
82) RHR Residual Heat Removal
83) RI-ISI Risk Informed - Inservice Inspection
84) RPV Reactor Pressure Vessel
85) RV Relief Valve
86) SAMA Severe Accident Management Alternative Analysis
87) SBO Station Blackout
88) SER Safety Evaluation Report
89) SLC Standby Liquid Control
90) SPAR Standardized Plant Analysis Risk (Model)
91) SR Supporting Requirement
92) SRV Safety Relief Valve
93) SV Solenoid Valve
94) TR Topical Report
95) TS Technical Specification
96) WW Wetwell

2. Methodology

A simplified bounding analysis approach consistent with the EPRI approach is used for evaluating the change in risk associated with permanently increasing the CGS integrated leak rate test interval to fifteen years. The approach is consistent with that presented in Appendix H of EPRI Report No. 1009325, Revision 2, *Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals* (Reference 26), EPRI TR-104285 (Reference 2), NUREG-1493 (Reference 6) and the Calvert Cliffs liner corrosion analysis (Reference 5). The analysis uses results from a Level 2 analysis of core damage scenarios from the current CGS PRA model and

subsequent containment response resulting in various fission product release categories (including no or negligible release).

The six general steps of this assessment are as follows:

1. Quantify the baseline risk in terms of the frequency of events (per reactor year) for each of the eight containment release scenario types identified in the EPRI report.
2. Develop plant-specific person-rem (population dose) per reactor year for each of the eight containment release scenario types from plant specific consequence analyses.
3. Evaluate the risk impact (i.e., the change in containment release scenario type frequency and population dose) of permanently extending the ILRT interval to fifteen years.
4. Determine the change in Large Early Release Frequency (LERF) in accordance with RG 1.174 (Reference 4) and compare the change with the acceptance guidelines of RG 1.174.
5. Determine the impact on the Conditional Containment Failure Probability (CCFP).
6. Evaluate the sensitivity of the results to assumptions in the liner corrosion analysis, external events and to the fractional contribution of increased large isolation failures (due to liner breach) to LERF.

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

- Consistent with the other industry containment leak risk assessments, the CGS assessment uses LERF and delta-LERF in accordance with the risk acceptance guidance of RG 1.174. Changes in population dose and conditional containment failure probability are also considered to show that defense-in-depth and the balance of prevention and mitigation is preserved.
- If containment overpressure is credited in the ECCS recirculation analysis, and is included in the assessment, an additional figure of merit is core damage frequency (CDF) to ensure that the guidelines from RG 1.174 are met. Containment overpressure is not applicable to CGS and therefore CDF is not a figure of merit.
- This evaluation for CGS uses ground rules and methods to calculate changes in risk metrics that are similar to those used in Appendix H of EPRI Report No. 1009325, Revision 2, *Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals* (Reference 26).

3. Calculation Ground Rules and Assumptions

The following ground rules and assumptions are used in the analysis (it should be noted that many of these ground rules were cited explicitly in Reference 26):

1. The technical adequacy of the CGS PRA is consistent with the requirements of Regulatory Guide 1.200 as is relevant to this ILRT interval extension.
2. The CGS Level 1 and Level 2 internal events PSA models provide representative results.
3. It is appropriate to use the CGS internal events PSA model as a gauge to effectively describe the risk change attributable to the ILRT extension. It is reasonable to assume that the impact

from the ILRT extension (with respect to percent increases in population dose) will not substantially differ if fire and seismic events were to be included in the calculations.

4. Dose results for the containment failures modeled in the PRA can be characterized by information provided for the Severe Accident Management Alternative (SAMA) analysis in the *CGS WinMACCS Assessment of Severe Accident Consequences* (Reference 27) and also in the SAMA portion of the CGS License Renewal Application (Reference 28).
5. Accident classes describing radionuclide release end states are defined consistent with EPRI methodology (Reference 2) and are summarized in Section 4.2.
6. The representative containment leakage for Class 1 sequences is 1 La. Class 3 accounts for increased leakage due to Type A inspection failures.
7. The representative containment leakage for Class 3a sequences is 10La based on the previously approved methodology performed for Indian Point Unit 3 (References 8 and 9).
8. The representative containment leakage for Class 3b sequences is 100La based on the guidance provided in EPRI Report No. 1009325, Revision 2.
9. The Class 3b can be very conservatively categorized as LERF based on the previously approved methodology (References 8 and 9).
10. The impact on population doses from containment bypass scenarios is not altered by the proposed ILRT extension, but is accounted for in the EPRI methodology as a separate entry for comparison purposes. Since the containment bypass contribution to population dose is fixed, no changes on the conclusions from this analysis will result from this separate categorization.
11. The reduction in ILRT frequency does not impact the reliability of containment isolation valves to close in response to a containment isolation signal.
12. All quantifications for this analysis were performed at a 2.0E-12/yr truncation limit.
13. The "with maintenance" CGS Model of Record (MOR), References 17 and 44, was used for all quantitative results.
14. The random containment large isolation failure probability for large valves (8.36E-4) is assumed to equal the CGS Bayesian-updated probability for a safety-related motor-operated valve failing to close on demand found in Reference 18 (*Bayesian Update of CGS PSA Data, Revision 4*). The assumption is consistent with the wording in Section 4.3 of Reference 26, which states, "*Class 2 sequences: This group consists of all core damage accident progression bins for which a pre-existing leakage due to failure to isolate the containment occurs. These sequences are dominated by failure to close of large (>2 inches [5.1 cm] in diameter) containment isolation valves.*"

4. <u>Calculation Inputs</u>

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

4.0 Industry 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, Appendix H (Reference 26)

The first study referenced above is applicable because it provides one basis 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 for 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 CGS. 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. The contents of the above resources are briefly discussed below.

<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; that is reduction in ILRT frequency from 3 per 10 years to 1 per 20 years results in an "imperceptible" increase in risk.

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

EPRI TR-104285 (Reference 2)

Extending the risk assessment impact beyond shutdown (the earlier EPRI TR-105189 study), the EPRI TR-104285 study is a quantitative evaluation of the impact of extending

ILRT and LLRT test intervals on at-power public risk. This study combined IPE Level 2 models with NUREG-1150 Level 3 population dose models to perform the analysis. The study also used the approach of NUREG-1493 in calculating the increase in pre-existing leakage probability due to extending the ILRT and LLRT test intervals.

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

1. Containment intact and isolated
2. Containment isolation failures dependent upon the core damage accident
3. Type A (ILRT) related containment isolation failures
4. Type B (LLRT) related containment isolation failures
5. Type C (LLRT) related containment isolation failures
6. Other penetration related containment isolation failures
7. Containment failures due to core damage accident phenomena
8. Containment bypass

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

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

<u>NUREG-1150 (Reference 15) and NUREG/CR-4551 (Reference 7)</u>

NUREG-1150 and the technical basis, NUREG/CR-4551, provide an ex-plant consequence analysis for a spectrum of accidents including a severe accident with the containment remaining intact (i.e., Tech Spec Leakage). This ex-plant consequence analysis is calculated for the 50-mile radial area surrounding Peach Bottom. The ex-plant calculation can be delineated to total person-rem for each identified Accident Progression Bin (APB) from NUREG/CR-4551. It should be noted that in the analysis for the CGS ILRT extension, offsite dose consequence information from the SAMA analysis conducted for CGS License Renewal Application (References 27 and 28) is utilized in this analysis.

<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.

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

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

EPRI Report No. 1009325, Revision 2-A, Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals (Reference 24)

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 CGS assessment to determine the estimated increase in risk associated with the permanent 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.

4.1 Plant Specific Inputs

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

- Level 1 model results (Reference 17)
- Level 2 model results (References 17 and 44)
- Offsite Population Dose estimates from the SAMA Analysis (Reference 27)
- Release category definitions used in the Level 2 Model (References 17 and 44)
- ILRT results to demonstrate adequacy of the administrative and hardware issues (References 35 and 39)
- Containment failure probability data (References 17 and 44)
- Information regarding the technical adequacy of the CGS model to address this application (see Appendix A)

4.1.1 Level 1 Model

The Level 1 PSA model that is used for CGS is characteristic of the as-built, as-operated plant. The current Level 1 model is a linked fault tree model, and was quantified with the total Core Damage Frequency (CDF) of 6.02E-6/yr.

When each Level 2 release term was quantified, the results of several accident sequence sub-classes (1H, 2B, 5A, and 5B) revealed a release term that was slightly greater than the CDF for these accident sequence sub-classes; these differences are attributable to success term conservatisms in the Level 2 model and the application of the minimum cutset upper bound (MCUB) approximation when calculating the combined CDF value from the sum of the individual cutsets. This difference between the CDF and release term solutions for these sub-classes was added to the quantified CDF value and a result of 6.05E-6/yr was obtained; therefore, a value of 6.05E-6/yr is conservatively utilized for the ILRT risk calculations (it should be noted that this increase is less than 1% of the quantified CDF value).

Table 4-1 provides a summary of the internal events (including internal flooding) initiating event contribution CDF. Table 4-2 provides a summary of the internal events (including internal flooding) accident classification contribution to CDF.

Table 4-1 – Initiating Events CDF Contribution

Initiator Group	%CDF
Internal Flooding	26%
Loss of Feedwater	20%
Loss of Condenser	12%
Manual Shutdown	8%
MSIV Closure	5%
Loss of Feedwater / ATWS	4%
Loss of Instrument Air	3%
IORV / SORV	3%
Reactor Level Instrument Line Break	2%
Loss of Offsite Power	2%
Loss of Condenser / ATWS	2%
MSIV Closure / ATWS	2%
Turbine Trip	2%
Dual Loss of SL-73 and SL-83	2%
Other	7%

Table 4-2 – Accident Class CDF Contribution

Class	Accident Class	Frequency	%CDF
Class I	Loss of Makeup	3.61E-06	59.6%
Class II	Loss of DHR	1.94E-06	32.1%
Class III	LOCA	5.48E-09	0.1%
Class IV	ATWS	2.11E-07	3.5%
Class V	Containment Bypass	1.99E-07	3.3%
Class VI	Station Blackout	8.77E-08	1.5%

The CGS PRA model of record addresses internal events (including internal flooding) only. Internal fire, seismic, and other external hazards are addressed in Section 5.4.2.

4.1.2 Level 2 Model

The Level 2 Model that is used for CGS was developed to calculate the LERF contribution as well as the other release categories evaluated in the model. Table 4-3 defines the release terms by magnitude and timing. Table 4-4 summarizes the pertinent CGS results in terms of release category.

The quantified value for LERF (H/E) release at a 2.0E-12/yr truncation limit is 3.27E-7/yr. A comparison of the Level 1 and Level 2 accident class contribution results indicated that a small adjustment was necessary to LERF to ensure that releases for accident classes where an "intact" release was not deemed to be credible (i.e. 3E, 4BA, and 4BL); the difference in the core damage contributions and the total release for these accident classes was incorporated into the LERF release term; as a result the LERF for the calculation of release terms in the ILRT release calculations is 3.28E-7/yr (an insignificant increase over the base PRA LERF of 3.27E-7/yr).

The quantified value for H/I release at a 2.0E-12/yr truncation limit is 2.96E-7/yr. A comparison of the Level 1 and Level 2 accident class contribution results indicated that a small adjustment was also necessary to H/I to ensure that releases for accident classes where an "intact" release was not deemed to be credible but for which the accident sequence containment event tree (CET) does not contain a LERF term (i.e. 1B0 and 2D); the difference in the core damage contributions and the total release for these accident classes was incorporated into the H/I release term; as a result the H/I for the calculation of release terms in the ILRT release calculations is 3.39E-7/yr (a 14.5% increase over 2.96E-7/yr).

Table 4-3 – Release Severity and Timing Classification[1]

Release Severity Term Release Fraction		Release Timing	
Classification Category	Cs Iodide % in Release	Classification Category	Time of Release[2]
High (H)	Greater than 10	Late (L)	Greater than 24 hours
Moderate (M)	1 to 10	Intermediate (I)	3 to 24 hours
Low (L)	0.1 to 1	Early (E)	Less than 3 hours
Low-low (LL)	Less than 0.1		
Intact (OK)	~ 0		

(1) The combinations of severity and timing classifications results in one OK release category and 12 other release categories of varying times and magnitudes.

(2) The cue for the General Emergency declaration is taken to be the time when EALs are exceeded. The declaration of the General Emergency begins the time for evacuation.

Table 4-4 – Level 2 PSA Model Release Categories and Frequencies

Release Category	Description	Frequency (yr^{-1})
LERF	Large Early Release	3.28E-07
H/I	High Intermediate Release	3.39E-07
M/E	Medium Early Release	1.19E-07
M/I	Medium Intermediate Release	2.22E-06
L/E	Low Early Release	2.22E-08
L/I	Low Intermediate Release	3.82E-09
LL/E	Low-Low Early Release	3.38E-07
LL/I	Low-Low Intermediate Release	4.80E-07
CI	Containment Intact	2.20E-06
Release Total	Total Level 2 Release (Not Intact)	3.85E-06
CDF	Core Damage Frequency	6.05E-06

4.1.3 Population Dose Calculations

The population dose values (in terms of person-rem) reported in the Severe Accident Management Alternative (SAMA) Analysis and the License Renewal Application (References 27 and 28) were utilized for the ILRT application; this information is presented in Table 4-5.

The frequencies for each release category in Table 4-4 are then used to calculate a "population dose risk" term, which is the product of the release frequency from Table 4-4 and the population dose. The results of this calculation are presented in Table 4-5.

It should be noted that the LERF (H/E) frequency term was decomposed for the purpose of dose rate calculations into BOC (break outside containment) and non-BOC terms. This was done by subtracting the LERF contribution from Class V release term as well as the Class 2 large containment isolation failure term calculated from the methodology obtained

from Section 4.3 of Reference 26. The Class 2 containment isolation failure frequency ($F_{Class\ 2}$) is

$$F_{Class\ 2} = PROB_{large\ CI} * CDF_{Total} \qquad \text{(Eqn. 4-1)}$$

Where,

$PROB_{large\ CI}$ = random containment large isolation failure probability (large valves); the parameter value (8.36E-4) is taken to equal the CGS Bayesian-updated probability for a safety-related motor-operated valve failing to close on demand found in Reference 18 (Bayesian Update of CGS PSA Data, Revision 4).

CDF_{Total} = total plant-specific core damage frequency.

The LERF (H/E) release term associated with break outside containment sequences ($LERF_{BOC}$) and non-BOC sequences ($LERF_{NON\text{-}BOC}$) are calculated as follows:

$$LERF_{BOC} = LERF_{Class\ V} + F_{Class\ 2} \qquad \text{(Eqn. 4-2)}$$

$$LERF_{NON\text{-}BOC} = LERF_{Total} - LERF_{BOC} \qquad \text{(Eqn. 4-3)}$$

Where,

$LERF_{Total}$ = total plant-specific large early release frequency.

$LERF_{Class\ V}$ = large early release frequency associated with Class V (containment bypass)

Numerically,

$F_{Class\ 2}$ = 8.36E-4 * 6.05E-6/yr = 5.06E-9/yr

$LERF_{BOC}$ = 1.99E-7/yr + 5.06E-9/yr = 2.04E-7/yr

$LERF_{NON\text{-}BOC}$ = 3.28E-7/yr - 2.04E-7/yr = 1.24E-7/yr

Table 4-5 – Population Dose and Dose Risk Calculations

Release Category	Population Dose (Person-Rem)	Frequency (yr^{-1})	Population Dose Risk (Person-Rem / yr)
$LERF_{BOC}$	2.01E+06	2.04E-07	4.10E-01
$LERF_{NON-BOC}$	2.01E+06	1.24E-07	2.50E-01
H/I	1.45E+06	3.39E-07	4.92E-01
M/E	9.39E+05	1.19E-07	1.12E-01
M/I	9.89E+05	2.22E-06	2.20E+00
L/E	1.36E+06	2.22E-08	3.02E-02
L/I	9.91E+05	3.82E-09	3.78E-03
LL/E	1.14E+05	3.38E-07	3.85E-02
LL/I	2.33E+05	4.80E-07	1.12E-01
CI	6.46E+01	2.20E-06	1.42E-04

4.1.4 Release Category Definitions

Table 4-6 defines the accident classes used in the ILRT extension evaluation, which is consistent with the EPRI methodology (Reference 26). These containment failure classifications are used in Section 5 of this analysis to determine the risk impact of extending the Containment Type A test interval.

Table 4-6 – EPRI Containment Failure Classification

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 La, under Appendix J for that plant.
2	Containment isolation failures (as reported in the IPEs) include 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 include those accidents in which the pre-existing isolation failure to seal is not dependent on the sequence in progress. This class is similar to Class 4 isolation failures, but is applicable to sequences involving Type C tests and their potential failures.

Class	Description
6	Containment isolation failures include those leak paths covered in the plant test and maintenance requirements or verified per in service inspection and testing (ISI/IST) program.
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.

4.1.5 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 permanent 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 4-6, 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 26). For Class 3a, the probability is based on the maximum likelihood estimate of failure (arithmetic average) from the available data (i.e., two "small" failures in 217 tests leads to two "large" failures in 217 tests (i.e., 2 / 217 = 0.0092). For Class 3b, the probability is based on the Jeffrey's 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 ΔLERF 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 CGS is detailed in Section 5.0.

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.

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

An estimate of the likelihood and risk impact 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.

Section 5.4.1 fully discusses the methodology and the results as it pertains to the CGS ILRT extension.

5. ILRT Extension Detailed Calculation

The application of the approach based on the guidance contained in EPRI Report No. 1009325, Revision 2-A, Appendix H (Reference 26), EPRI TR-104285 (Reference 2) and previous risk assessment submittals on this subject (References 5, 8, 21, 22, and 23) have led to the results as described in this section. The results are displayed according to the eight accident classes defined in the EPRI report, as described in Table 5-1.

Table 5-1 – Accident Classes (Containment Release Types)

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 analysis performed examined CGS-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 TR-104285, Class 1 sequences [Reference 2]).
- Core damage sequences in which containment integrity is impaired due to random isolation failures of plant components other than those associated with Type B or Type C test components. For example, liner breach or bellow leakage (EPRI TR-104285, Class 3 sequences).
- Accident sequences involving containment bypassed (EPRI TR-104285, Class 8 sequences), large containment isolation failures (EPRI TR-104285, Class 2 sequences), and small containment isolation "failure-to-seal" events (EPRI TR-104285, Class 4 and 5 sequences) are accounted for in this evaluation as part of the baseline risk profile. However, they are not affected by the ILRT frequency change.
- 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.

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 5-1.

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

Step 3 - Evaluate risk impact of extending Type A test interval from 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) and the impact on the Conditional Containment Failure Probability (CCFP).

Step 5 – Perform sensitivity analyses.

Each of these steps is developed and documented in the sections below.

5.0 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 TR-104285). The question on containment integrity was modified to include the probability of a liner breach or bellows failure (due to excessive leakage) at the time of core damage. Two failure modes were considered for the Class 3 sequences. These are Class 3a (small breach) and Class 3b (large breach).

The frequencies for the severe accident classes defined in Table 5-1 were developed for CGS by first determining the frequencies for Classes 1, 2, 7 and 8 using the categorized sequences and the identified correlations shown in Table 5-3, scaling these frequencies to account for the uncategorized sequences, determining the frequencies for Classes 3a and 3b, and then determining the remaining frequency for Class 1. It should be noted that per the rationale presented in EPRI TR-104285, EPRI Classes 4, 5, and 6 are not applicable to the quantification of the risk associated with an increase in ILRT Type A testing frequency (and are not addressed further in this analysis).

The development of the equations used and the method by which each EPRI class is addressed is contained Section 4.3 of Reference 26. Below are several explanatory notes outlining interpretations which are not specifically stated in that reference or in Table 5-3.

1. Class 1: Represented in Table 5-3 by (CDF_{total} - Release $Frequency_{total}$ – $F_{Class\ 3a}$ – $F_{Class\ 3b}$), where

    a) CDF_{total} represents the total core damage frequency calculated from the CGS model of record (References 17 and 44) at a truncation limit of 2.0E-12/yr; the value is obtained from the final row in Table 5-2. [1]
    b) Release $Frequency_{total}$ is the Level 2 model release frequency (both LERF and non-LERF sequences truncated at 2.0e-12/yr) as described in the CGS PRA model of

[1] Table 5-2 is a summary of the Level 2 model release terms as sorted by core damage accident classes/sub-classes. CDF, LERF, and Total Level 2 Release terms are displayed in this table.

record (References 17 and 44) and associated documentation; the value is taken from the final row in Table 5-2.

c) $F_{Class\ 3a}$ is the frequency for Class 3a releases as defined in Item 3b below.
d) $F_{Class\ 3b}$ is the frequency for Class 3b releases as indicated in Item 4b below.

2. Class 2: This group consists of all core damage accident progression bins for which a failure to isolate the containment occurs following the onset of core damage (as opposed to Class 8, where the containment is bypassed as part of the CDF accident sequence). The Class 2 frequency is estimated by multiplying total CDF by the probability of containment isolation failure (represented by the plant PRA-specific probability of a motor-operated valve to fail to close).

3. Class 3a:

a) From Reference 26 Section 5.2.1, the class 3a leakage probability ($PROB_{Class\ 3a}$) is based on data from the ILRT testing data (Section 3.5), which is two "small" failures in 217 tests (2/217=0.0092).
b) The formulation of the Class 3a frequency ($F_{Class\ 3a}$) involves the more detailed treatment presented in Section 5.2.1 of Reference 26:

$$F_{Class\ 3a} = (CDF_{total} - CDF_{AONL}) * PROB_{Class\ 3a} \qquad \text{(Eqn. 5-1)}$$

Where,

CDF_{AONL} = Always or Never LERF CDF; this parameter is quantified by the formula:

$$CDF_{AONL} = CDF_{Class\ 1B0} + CDF_{Class\ II} + CDF_{Class\ 3E} + CDF_{Class\ V} + CDF_{Class\ 6A2} + CDF_{Class\ 6B1} \qquad \text{(Eqn. 5-2)}$$

Where, $CDF_{Class\ 1B0}$, $CDF_{Class\ II}$, $CDF_{Class\ 3E}$, $CDF_{Class\ V}$, $CDF_{Class\ 6A2}$, and $CDF_{Class\ 6B1}$ are the core damage terms as defined in Table 5-2 (where it is demonstrated that the conditional large early release probability is either 1.0 or 0.0)

Numerically,

$$CDF_{AONL} = 5.679\text{-}07/yr + 1.94E\text{-}06/yr + 1.02E\text{-}09/yr + 1.99E\text{-}07/yr + 6.20E\text{-}09/yr = 2.71E\text{-}06/yr$$

$$F_{Class\ 3a} = (6.05E\text{-}06/yr - 2.71E\text{-}06/yr) * 0.0092 = 3.07E\text{-}08/yr$$

4. Class 3b:

a) From Reference 26 Section 5.2.1, the class 3b failure probability is based on the Jeffrey's Non-Informative Prior and is equal to 0.0023.

b) The formulation of the Class 3b frequency ($F_{Class\ 3b}$) involves the more detailed treatment presented in Section 5.2.1 of Reference 26; this treatment is the same as is outlined above for Class 3a.

$$F_{Class\ 3b} = (CDF_{total} - CDF_{AONL}) * PROB_{Class\ 3b} \qquad \text{(Eqn. 5-3)}$$

Numerically,

$$F_{Class\ 3b} = (6.05E\text{-}06/yr - 2.71E\text{-}06/yr) * 0.0023 = 7.67E\text{-}09/yr$$

5. Class 7: This class encompasses phenomenologically-induced containment failures (both early and late in the sequence). This is interpreted to encompass all of the accident classes not assigned to other EPRI categories (those not involving containment bypass and containment isolation failure). The frequency for this class is the sum of all the release frequencies in Table 4-5 with the exception of $LERF_{BOC}$.

6. Class 8: This group consists of all core damage accident progression bins in which containment bypass occurs. Each plant's PRA is used to determine the containment bypass contribution. Contributors to bypass events include ISLOCA events and break outside containment (BOC) events with an isolation failure. Class 8 in the CGS containment model is represented by the CDF Accident Class V (containment bypass).

Table 5-2 – Internal Events Core Damage, LERF, and Total Release by Accident Class

PDS Class	PDS Description	PDS Subclass	Subclass CDF [yr^{-1}]	Class CDF [yr^{-1}]	LERF [yr^{-1}]	Total Release Frequency [yr^{-1}]
I (Loss of Makeup)	Loss of control and service air sequences with early failure of HPCS, RCIC and RPV depressurization.	A1	1.21E-07	3.61E-06	1.04E-09	5.65E-09
	Transient and small LOCA sequences with early failure of HPCS, RCIC and RPV depressurization.	A2	1.83E-06		2.52E-08	5.87E-07
	Loss of offsite power sequences with failure of high pressure injection and failure to depressurize.	A3	4.24E-08		1.15E-10	4.21E-09
	Transients in which high pressure injection fails and RPV depressurization succeeds. Containment heat removal is unavailable.	B0	5.69E-07		0.00E+00	5.69E-07
	SBO and loss of inventory makeup (BE: CD at < 4 hrs, BL: CD > 4 hrs)	1G	1.02E-06		5.49E-09	2.92E-07
		1H	2.42E-08		2.34E-10	2.42E-08
II (Loss of Decay Heat Removal)	Loss of containment heat removal with RPV initially intact; core damage (CD) induced post containment failure	B	2.88E-07	1.94E-06	0.00E+00	2.88E-07
	Loss of containment heat removal with RPV breached but no initial CD; CD induced post containment failure	D	1.65E-06		0.00E+00	1.65E-06
III (LOCA)	Medium LOCA with successful depressurization or large LOCA. Early failure of HPCS and low pressure injection.	C	4.46E-09	5.48E-09	2.42E-11	1.62E-09
	LOCA sequences with failure of vapor suppression, and assumed failure of injection. Core damage is at low pressure, with containment failed.	E	1.02E-09		1.02E-09	1.02E-09
IV (ATWS)	ATWS with vessel intact at time of core uncovery, which indicates high pressure core melt with containment failed.	BA	9.18E-08	2.11E-07	4.15E-08	9.18E-08
	ATWS with vessel failed at time of core uncovery, which indicates low pressure core melt with containment failed.	BL	1.19E-07		5.40E-08	1.19E-07

PDS Class	PDS Description	PDS Subclass	Subclass CDF [yr^{-1}]	Class CDF [yr^{-1}]	LERF [yr^{-1}]	Total Release Frequency [yr^{-1}]
V (Containment Bypass)	Large or medium LOCA outside containment with failure to isolate the break.	5A	1.90E-07	1.99E-07	1.90E-07	1.90E-07
	Small LOCA outside containment with failure to isolate the break.	5B	8.97E-09		8.97E-09	8.97E-09
VI (Station Blackout)	Station blackout sequences with early failure of HPCS and RCIC.	A1	8.15E-08	8.77E-08	6.16E-10	1.35E-08
	Station blackout sequences with a stuck-open relief valve, no containment heat removal, but successful injection until containment failure.	A2	0.00E+00		0.00E+00	0.00E+00
	Station blackout sequences with initial success of HPCS. HPCS operation is recoverable if ac power is restored. Containment heat removal is unavailable.	B1	6.20E-09		0.00E+00	1.32E-09
	Long-term SBO with RCIC operating at time of battery depletion. HPCS is failed.	B2	0.00E+00		0.00E+00	0.00E+00
All	**Total**		6.05E-06	6.05E-06	3.28E-07	3.85E-06

Table 5-3 – EPRI Containment Release Type Tabulation

EPRI Class	Description	Formula (Resultant Frequency) (3)	Resultant Frequency [yr^{-1}] (4)	Dose [person-rem]	Dose Rate [person-rem/yr] (5)
1	Containment Intact	CDF_{total}-Release $Frequency_{total}$ - $F_{class\ 3a}$ -$F_{class\ 3b}$	2.16E-06 (2)	64.6 (6)	1.40E-04 (2)
2	Large Containment Isolation Failures (1)	$PROB_{large\ CI}$ * CDF_{total}	5.06E-09	2.01E+06 (7)	1.02E-02
3a	Small Pre-Existing Leak in Containment	$PROB_{Class\ 3a}$ * (CDF_{total} - CDF_{AONL})	3.07E-08	646 (8)	1.98E-05
3b	Large Pre-Existing Leak in Containment	$PROB_{Class\ 3b}$*(CDF_{total} - CDF_{AONL})	7.67E-09	6460 (9)	4.95E-05
7	Severe accident phenomena-induced containment failures (early and late)	Σ(All release categories except intact and BOC from Table 4-5) (11)	3.65E-06	8.87E+05 (10)	3.23E+00 (11)
8	Containment Bypass sequences	$CDF_{Class\ V}$	1.99E-07	2.01E+06 (7)	4.00E-01

Notes:
(1) Random Containment Large Isolation failure probability, $PROB_{large\ CI}$, is taken to equal the CGS Bayesian-updated probability for a safety-related motor-operated valve failing to close on demand (CGS Component Data Notebook), 8.36E-4.
(2) EPRI Class 1 "containment intact" term in this table differs slightly from the value listed in Table 4-5 due to the subtraction of the frequencies for Class 3a and Class 3b in this table.
(3) Formulas based upon information contained in Section 5.0.
(4) Frequencies calculations are based upon equations in the "Formula (Resultant Frequency)' column and the written description for each accident class contained in Section 5.0.
(5) Unless otherwise noted, dose rates are calculated by multiplying the values in the "Resultant Frequency" and "Dose" columns.
(6) Value obtained from the "CI" release term in Table 4-5.
(7) Value obtained from the "LERF-BOC" release term in Table 4-5.
(8) Pre-existing small leak population dose equal to 10 times EPRI accident Class 1 population dose per Section 5.2.2 of Reference 26.
(9) Pre-existing large leak population dose equal to 100 times EPRI accident Class 1 population dose per Section 5.2.2 of Reference 26.
(10) Dose for Class 7 is obtained by dividing the "Dose Rate" result by the "Resultant Frequency" result.
(11) Dose for Class 7 is obtained by summing the product of the "Frequency" and "Population Dose Risk" columns for each release category (with the exception of LERF-BOC and CI) in Table 4-5.

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

Plant-specific release analyses were performed to estimate the person-rem doses to the population within a 50-mile radius from the plant. These releases are presented and discussed in Section 4.1.3 and Table 4-5. The population dose values reported in the Severe Accident Management Alternative (SAMA) Analysis in the License Renewal Application (References 27 and 28) were utilized for this analysis. The plant-specific person-rem dose results are presented in Table 5-3.

5.2 Step 3 - Evaluate Risk Impact of Extending Type A Test Interval to once per 15 years

In this step, the risk impact associated with the change in ILRT testing intervals is evaluated in terms of changes to the accident class frequencies and populations doses. This is accomplished in a three-step process (these steps are referred to as sub-steps to distinguish them from the overall steps).

In the first sub-step, the change in probability of leakage detectable only by ILRT (Classes 3a and 3b) for the new surveillance intervals of interest is determined. NUREG 1493 (Reference 5) states that relaxing the ILRT frequency from three in 10 years to one in 10 years will increase the average time that a leak that is detectable only by ILRT goes undetected from 18 to 60 months (1/2 the surveillance interval), a factor of 60/18 = 3.33 increase. Therefore, relaxing the ILRT testing frequency from three in 10 years to one in 15 years will increase the average time that a leak that is detectable only by ILRT goes undetected from 18 to 90 months (1/2 the surveillance interval), a factor of 90/18 = 5.0 increase.

In the second sub-step, the population dose rate for the new surveillance intervals of interest is determined by multiplying the dose by the frequency for each of the accident classes. In sub-step three, the accident class dose rates are then summed to obtain the total dose rate.

The results of the aforementioned sub-steps are contained in Table 5-4.

Table 5-4 - Accident Class Frequency and Population Doses versus ILRT Frequency

EPRI Accident Class	ILRT Frequency					
	3 per 10 years		1 per 10 years		1 per 15 years	
	Frequency [yr^{-1}]	Person-rem/yr	Frequency [yr^{-1}]	Person-rem/yr	Frequency [yr^{-1}]	Person-rem/yr
1	2.16E-06	1.40E-04	2.07E-06	1.34E-04	2.01E-06	1.30E-04
2	5.06E-09	1.02E-02	5.06E-09	1.02E-02	5.06E-09	1.02E-02
3a	3.07E-08	1.98E-05	1.02E-07	6.60E-05	1.53E-07	9.91E-05
3b	7.67E-09	4.95E-05	2.55E-08	1.65E-04	3.83E-08	2.48E-04
7	3.65E-06	3.23E+00	3.65E-06	3.23E+00	3.65E-06	3.23E+00
8	1.99E-07	4.00E-01	1.99E-07	4.00E-01	1.99E-07	4.00E-01
Totals	6.05E-06	3.64E+00	6.05E-06	3.64E+00	6.05E-06	3.64E+00

5.3 Step 4 – Evaluate Change in LERF and CCFP

In this step, the changes in LERF and CCFP as a result of the evaluation of extended ILRT intervals are evaluated.

The risk 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 containment could produce a large release due to a leakage path that develops and is undetected during the extended interval. As discussed in References 1 and 2, only Class 3 sequences have the potential to result in early releases if a pre-existing, undetected leak were present. Late releases are excluded regardless of size of the leak because late releases are not, by definition, LERF events. The frequency of class 3b sequences is used as a measure of LERF, and the change to LERF is determined by the change in class 3b frequency. Refer to Regulatory Guide 1.174 (Reference 4) for LERF acceptance guidelines.

Delta LERF is determined using the equation below, where the "frequency of class 3b new interval x" is the frequency of the EPRI accident class 3b for the ILRT interval of interest and the "frequency of class 3b baseline" is defined as the EPRI accident class 3b frequency for ILRTs performed on a three-per-10-years basis.

$$\Delta LERF = (\text{freq. of class 3b new interval x}) - (\text{freq. of class 3b baseline}) \qquad \text{(Eqn. 5-4)}$$

The conditional containment failure probability (CCFP) is defined as the probability of containment failure given the occurrence of a core damage accident, which is expressed as:

$$CCFP = [1 - (F_{Class\ 1} + F_{class\ 3a}) / CDF] * 100\% \qquad \text{(Eqn. 5-5)}$$

Where,

$F_{Class\ 1}$ is the frequency of EPRI Class 1 release from the "frequency" columns in Table 5-4.

$F_{Class\ 3a}$ is the frequency of EPRI Class 3a release from the "frequency" columns in Table 5-4.

The increase in CCFP is expressed as:

$$\Delta CCFP = (\text{CCFP at ILRT revised interval}) - (\text{CCFP at baseline interval}) \qquad \text{(Eqn. 5-6)}$$

Table 5-5 – CGS Delta LERF and CCFP

Risk Metric	ILRT Testing Frequency		
	3 in 10 years	1 in 10 years	1 in 15 years
ΔLERF	N/A	1.79E-08	3.07E-08
CCFP	63.77%	64.06%	64.28%
ΔCCFP	N/A	0.30%	0.51%

5.4 Step 5 – Evaluate Sensitivity of Results

This step investigates the sensitivity of assumptions related to liner corrosion, the impact of external events.

In evaluating the impact of liner corrosion on the extension of ILRT testing intervals, the Calvert Cliffs methodology is used. The methodology developed for Calvert Cliffs investigates how an age-related degradation mechanism can be factored into the risk impact associated with longer ILRT testing intervals.

An assessment of the impact of external events is performed. The primary basis for this investigation is the determination of the total LERF following an increase in the ILRT testing frequency from three times in 10 years to once per 15 years.

Section 1.2 of Reference 26 states the following regarding containment overpressure:

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

Since containment overpressure is not required in the CGS design basis or the CGS PRA model to support ECCS performance to mitigate accidents at CGS, the effect of the ILRT extension on containment overpressure need not be addressed.

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

This sensitivity study presents an estimate of the likelihood and risk implications of corrosion-induced leakage of steel containment liners occurring and remaining undetected during the extended ILRT test intervals evaluated in this report. The methodology employed in this sensitivity case is taken from the Calvert Cliffs liner corrosion analysis (References 5 and 20). The Calvert Cliffs analysis is performed for a concrete cylinder and dome with a concrete basemat, each with a steel liner. The CGS containment is a BWR Mark II with a steel shell in the drywell and wetwell regions. The shell in the drywell is surrounded by a concrete shield.

The following approach is used to determine the change in likelihood, due to extending the ILRT interval, of detecting corrosion of the steel liner. This likelihood is used to determine the potential change in risk in the form of a sensitivity case. Consistent with the Calvert Cliffs analysis, the following are addressed:

1. Differences between the containment basemat and other regions of the containment
2. The historical steel liner/shell flaw likelihood due to concealed corrosion
3. The impact of aging
4. The likelihood that visual inspections will be effective in detecting a flaw

The assumptions used in this sensitivity study are consistent with the Calvert Cliffs methodology and include the following:

1. A half failure is assumed for the basemat concealed liner corrosion due to lack of identified failures.
2. Two corrosion events are used to estimate the liner flaw probability. These events, one at North Anna Unit 2 and the other at Brunswick Unit 2, were initiated from the non-visible (backside) portion of the containment liner.
3. Consistent with the Calvert Cliff's analysis, the estimated historical flaw probability is limited to 5.5 years to reflect the years since September 1996, when 10CFR50.55a started requiring visual inspections. Additional success data were not used to limit the aging impact of the corrosion issue, even though inspections were being performed prior to this data (and have been performed since the timeframe of the Calvert Cliffs analysis) and there has been no evidence that additional corrosion issues were identified.
4. Consistent with the Calvert Cliffs analysis, the corrosion-induced steel liner/shell flaw likelihood is assumed to double every five years. This is based solely on judgment and is included in this analysis to address the increase in likelihood of corrosion as the steel shell ages.
5. 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 that corresponds to the ILRT pressure of 37 psig. For CGS, the containment failure probabilities are conservatively assumed to be 10% for the shell wall and 1% for the basemat.
6. In the Calvert Cliffs analysis, it is noted that approximately 85% of the interior wall surface is accessible for visual inspections. The Columbia interior wall surface accessible for visual inspections is estimated to be at least 90% (the majority of uninspectable wall surface being the area between the drywell floor slab and the DW-WW omega seal) per Reference 38. Therefore, consistent with the Calvert analysis, a 5% visual inspection detection failure likelihood given the flaw is visible and a 5% likelihood of a non-detectable flaw is used. This results in a total undetected flaw probability of 10%, which is assumed in the base case analysis.
7. All non-detectable failures are assumed to result in early releases. This approach is conservative and avoids detailed analysis of containment failure timing and operator recovery actions.

The results of the liner corrosion analysis for the purpose of the calculation of the likelihood of non-detected containment leakage described above are summarized in Table 5-6.

Table 5-6 – Liner Corrosion Analysis

Step	Description	Containment (Excluding Basemat)	Containment Basemat
1	Historical Steel Liner Flaw Likelihood / Failure Data	Events: 2 2 / (70 * 5.5) 5.19E-03	Events: 0 (assume half a failure) 0.5 / (70 * 5.5) 1.30E-03
	Failure Data (1)	5.19E-03	1.30E-03
2	Age-Adjusted Steel Liner Flaw Likelihood (Year 1) (2)	2.05E-03	5.13E-04
	Age-Adjusted Steel Liner Flaw Likelihood (Avg Years 5-10) (2)	5.20E-03	1.30E-03
	Age-Adjusted Steel Liner Flaw Likelihood (Year 15) (2)	1.43E-02	3.59E-03
	Age-Adjusted Steel Liner Flaw Likelihood (Avg 15 Years) (2)	6.45E-03	1.61E-03
3	Flaw Likelihood (3 Years) (3a)	0.71%	0.18%
	Flaw Likelihood (10 Years) (3a)	4.14%	1.04%
	Flaw Likelihood (15 Years) (3a)	9.68% (3b)	2.42% (3c)
4	Likelihood of Breach in Containment Given Steel Liner Flaw (4)	1.00%	0.10%
5	Visual Inspection Detection Failure Likelihood	10.00% (5a)	100.00% (5b)
6	Likelihood of Non-Detected Containment Leakage (3 yr)	7.12E-06	1.78E-06
	Likelihood of Non-Detected Containment Leakage (10 yr)	4.14E-05	1.04E-05
	Likelihood of Non-Detected Containment Leakage (15 yr)	9.68E-05	2.42E-05

Notes:

(1) Containment location specific (consistent with Calvert Cliffs analysis).

(2) During 15-year interval, assume failure rate doubles every five years (14.9% increase per year). The average for fifth to tenth year set to the historical failure rate (consistent with Calvert Cliffs analysis).

(3) (a) Uses age-adjusted liner flaw likelihood (Step 2), assuming failure rate doubles every five years (consistent with Calvert Cliffs).

(b) Note that the Calvert Cliffs analysis presents the delta between three and 15 years of 8.7% to utilize in the estimation of the delta-LERF value. For this analysis, however, the values are calculated based on three-, 10-, and 15-year intervals, consistent with the desired presentation of the results.

(c) Note that the Calvert Cliffs analysis presents the delta between three and 15 years of 2.2% to utilize in the estimation of the delta-LERF value. For this analysis, however, the values are calculated based on the three-, 10-, and 15-year intervals, consistent with the desired presentation of the results.

(4) The failure probability of the cylinder and dome is assumed to be 1%, and basemat is 0.1% as compared to 1.1% and 0.11% in the Calvert Cliffs analysis.

(5) (a) 5% failure to identify visual flaws plus 5% likelihood that the flaw is not visible (not through cylinder but could be detected by ILRT). All events have been detected through visual inspection. Five percent visible failure detection is a conservative assumption.

(b) Cannot be visually inspected.

The cumulative likelihood of non-detected containment leak ($P_{leak\text{-}corr\text{-}tot}$) due to corrosion is the sum in Step 6 for the containment walls and the containment basemat:

1. At 3 years: 7.12E-06 + 1.78E-06 = 8.89E-06
2. At 10 years: 4.14E-05 + 1.04E-05 = 5.18E-05
3. At 15 years: 9.68E-05 + 2.42E-05 = 1.21E-04

The above factors are applied to those core damage accidents that are not already independently LERF or that could never result in LERF. For example, the three-in-10-years case is calculated as follows:

1. Per Table 5-4, the EPRI Class 3b frequency is 7.67E-09/yr.
2. As discussed in Section 5.2.1, the CGS CDF associated with accidents that are guaranteed to be LERF or could never result in LERF (CDF_{AONL}) per Eqn. 5-2 is 2.71E-06/yr. Thus, the value for "CDF_{total} - CDF_{AONL}" per Eqn. 5-3 is 6.05E-06/yr – 2.71E-06/yr = 3.33E-06/yr
3. The increase in the base case Class 3b frequency ($\Delta F_{3b\text{-}corr}$) due to the corrosion-induced concealed flaw issue is calculated based upon the formula:

$$\Delta F_{3b\text{-}corr} = (CDF_{total} - CDF_{AONL}) * P_{leak\text{-}corr\text{-}tot} \qquad \text{(Eqn. 5-7)}$$

   Numerically, this corresponds to 3.33E-06*8.89E-06=2.96E-11/yr, where 8.89E-6 was previously shown to be the cumulative likelihood of non-detected containment leakage due to corrosion at three years.
4. The three-in-10-years Class 3b frequency, including the corrosion-induced concealed flaw issue, is calculated as the sum of the baseline class 3b frequency without corrosion ($F_{Class\ 3b}$) from Eqn. 5-3 and the increase in class 3b frequency ($\Delta F_{3b\text{-}corr}$) due to corrosion from Eqn. 5-7 (7.67E-09/yr+2.96E-11/yr=7.70E-09/yr).

Table 5-7, Table 5-8, and Table 5-9 provide a summary of the base case as well as the corrosion sensitivity case for various ILRT intervals (three times per 10 years, once per 10 years, and once per 15 years, respectively).

Each of tables is sub-divided further into corrosion and non-corrosion cases. For both the corrosion and non-corrosion cases, the frequencies of the EPRI accident classes are provided. In the corrosion cases, an additional column titled "Delta person-rem per yr" is provided. The "Δ Person-rem / yr" column provides the change in person-rem per year between the corrosion and non-corrosion cases. Negative values in the "Δ Person-rem / yr" column indicate a reduction in the person-rem per year for the selected accident class; this occurs only in EPRI accident Class 1 and is a result of the reduction in the frequency of the

accident Class 1 and an increase in accident Class 3b. Rows for the totals, both frequency and dose rate, are provided in the tables. Additional summary rows are also provided.

1. The change in dose rate, expressed as person-rem/yr and percentage of the total base dose is provided in the row below the "total" row.
2. The Conditional Containment Failure Probability (CCFP) is provided in the next row, followed by the absolute change in CCPF in percentage points.
3. Class 3b LERF is also provided and indicates the accident class 3b frequency as well as the change in the class 3b frequency in parentheses. This difference is calculated between the non-corrosion and corrosion cases.
4. The next row titled "Delta LERF from Base Case (3 per 10 years)", which is not contained in Table 5-7, provides the change in LERF as a function of ILRT frequency from the base case. The difference between the non-corrosion and corrosion cases is contained in the last column underneath the heading "Difference".
5. The last row of the table titled "Delta LERF from 1 per 10 Years", which is only contained in Table 5-9, provides the change in LERF as a function of ILRT frequency from the "1 per 10 year" case. The difference between the non-corrosion and corrosion cases is contained in the last column underneath the heading "Difference".

The principal sensitivity analysis in this section presents an estimate of the likelihood and risk implications of corrosion-induced leakage of steel containment liners not being detected during the extended ILRT test intervals evaluated in this report. The analysis considers ILRT extension time, inspections, and concealed degradation in uninspectable areas. As can be seen from Table 5-7, Table 5-8, and Table 5-9, the change from the base case of three tests per 10 years to one test per 15 years in LERF with corrosion is very small (3.1E-08/yr). Similarly, the change in delta-LERF between the corrosion and non-corrosion cases for one per 15 years is, correspondingly, very small at 4.0E-10/yr. Additionally, no credit was given for supplemental containment inspections committed to under the aging management program integral with approval of CGS license renewal.

Table 5-7 – Summary of CGS Corrosion Analysis (3 per 10 yr ILRT Frequency)

EPRI Accident Class	ILRT Frequency				
	3 per 10 years				
	Without Corrosion		With Corrosion		
	Frequency [yr^{-1}] (1)	Person-rem/yr (1)	Frequency [yr^{-1}] (3)	Person-rem/yr (3)	Δ Person-rem / yr (8)
1	2.16E-06	1.40E-04	2.16E-06 (6)	1.40E-04 (7)	-1.92E-09
2	5.06E-09	1.02E-02	5.06E-09	1.02E-02	0.00E+00
3a	3.07E-08	1.98E-05	3.07E-08	1.98E-05	0.00E+00
3b	7.67E-09	4.95E-05	7.70E-09 (4)	4.97E-05 (5)	1.92E-07
7	3.65E-06	3.23E+00	3.65E-06	3.23E+00	0.00E+00
8	1.99E-07	4.00E-01	1.99E-07	4.00E-01	0.00E+00
Total	**6.05E-06**	**3.64E+00**	**6.05E-06**	**3.64E+00**	**1.90E-07**
Δ Dose	N/A				
CCFP	63.77% (2)		63.77% (12)		
ΔCCFP	N/A				
Class 3b LERF	7.67E-09 (9)		7.70E-09 (10)		**Delta 3b LERF**
					2.96E-11 (11)

Notes:

(1) Values taken from Table 5-4.
(2) Values taken from Table 5-5.
(3) Values for all classes except Class 1 and Class 3b are identical to the "without corrosion" values.
(4) Value calculated by summing "without corrosion" frequency and the ΔF value derived from Eqn. 5-7.
(5) Value obtained by multiplying the Class 3b "with corrosion" frequency calculated in this table and the dose for Class 3b listed in Table 5-3.
(6) Value calculated by using the formula for Class 1 listed in Table 5-3.
(7) Value obtained by multiplying the Class 1 "with corrosion" frequency calculated in this table and the dose for Class 1 listed in Table 5-3.
(8) The values in this column are the difference in dose rate (person-rem/yr) between the "with corrosion" and "without corrosion" cases.
(9) Value is identical to the Class 3b "without corrosion" frequency listed above.
(10) Value is identical to the Class 3b "with corrosion" frequency listed above.
(11) Value is the difference in the "with corrosion" and "without corrosion" Class 3b LERF values.
(12) Value calculated based upon Eqn. 5-5.

Table 5-8 – Summary of CGS Corrosion Analysis (1 per 10 yr ILRT Frequency)

EPRI Accident Class	ILRT Frequency				
	1 per 10 years				
	Without Corrosion		With Corrosion		
	Frequency [yr^{-1}] (1)	Person-rem/yr (1)	Frequency [yr^{-1}] (3)	Person-rem/yr (3)	Δ Person-rem / yr (8)
1	2.07E-06	1.34E-04	2.07E-06 (6)	1.34E-04 (7)	-1.12E-08
2	5.06E-09	1.02E-02	5.06E-09	1.02E-02	0.00E+00
3a	9.57E-08	6.19E-05	1.02E-07	6.60E-05	0.00E+00
3b	2.39E-08	1.54E-04	2.57E-08 (4)	1.66E-04 (5)	1.12E-06
7	3.65E-06	3.23E+00	3.65E-06	3.23E+00	0.00E+00
8	1.99E-07	4.00E-01	1.99E-07	4.00E-01	0.00E+00
Total	**6.05E-06**	**3.64E+00**	**6.05E-06**	**3.64E+00**	**1.10E-06**
Δ Dose	1.56E-04 (17)		1.57E-04 (18)		
CCFP	64.06% (2)		64.07% (12)		
ΔCCFP	0.30% (2)		0.30% (13)		
Class 3b LERF	2.55E-08 (9)		2.57E-08 (10)		**Difference** 1.73E-10 (11)
Delta Class 3b LERF (from 3 in 10 yr base case)	1.79E-08 (14)		1.80E-08 (15)		**Difference** 1.43E-10 (16)

Notes:

(1) Values taken from Table 5-4.
(2) Values taken from Table 5-5.
(3) Values for all classes except Class 1 and Class 3b are identical to the "without corrosion" values.
(4) Value calculated by summing "without corrosion" frequency and the ΔF value derived from Eqn. 5-7.
(5) Value obtained by multiplying the Class 3b "with corrosion" frequency calculated in this table and the dose for Class 3b listed in Table 5-3.
(6) Value calculated by using the formula for Class 1 listed in Table 5-3.
(7) Value obtained by multiplying the Class 1 "with corrosion" frequency calculated in this table and the dose for Class 1 listed in Table 5-3.
(8) The values in this column are the difference in dose rate (person-rem/yr) between the "with corrosion" and without corrosion" cases.
(9) Value is identical to the Class 3b "without corrosion" frequency listed above.
(10) Value is identical to the Class 3b "with corrosion" frequency listed above.
(11) Value is the difference in the "with corrosion" and "without corrosion" Class 3b LERF values.
(12) Value calculated based upon Eqn. 5-5.
(13) Value is the difference between the "with corrosion" CCFP in this table minus the "with corrosion" CCFP in Table 5-7.
(14) Value is the difference between the "without corrosion" Class 3b LERF in this table minus the "without corrosion" Class 3b LERF in Table 5-7.
(15) Value is the difference between the "with corrosion" Class 3b LERF in this table minus the "with corrosion" Class 3b LERF in Table 5-7.
(16) Value is the difference in the "with corrosion" and "without corrosion" Delta Class 3b LERF values.
(17) Value is the difference between the "without corrosion" Dose (person-rem/yr) in this table minus the "without corrosion" Dose in Table 5-7.
(18) Value is the difference between the "with corrosion" Dose (person-rem/yr) in this table minus the "with corrosion" Dose in Table 5-7.

Table 5-9 – Summary of CGS Corrosion Analysis (1 per 15 yr ILRT Frequency)

EPRI Accident Class	ILRT Frequency				
	1 per 15 years				
	Without Corrosion		With Corrosion		
	Frequency [yr^{-1}] (1)	Person-rem/yr (1)	Frequency [yr^{-1}] (3)	Person-rem/yr (3)	Δ Person-rem / yr (8)
1	2.01E-06	1.30E-04	2.01E-06 (6)	1.30E-04 (7)	-2.61E-08
2	5.06E-09	1.02E-02	5.06E-09	1.02E-02	0.00E+00
3a	1.53E-07	9.91E-05	1.53E-07	9.91E-05	0.00E+00
3b	3.83E-08	2.48E-04	3.87E-08 (4)	2.50E-04 (5)	2.61E-06
7	3.65E-06	3.23E+00	3.65E-06	3.23E+00	0.00E+00
8	1.99E-07	4.00E-01	1.99E-07	4.00E-01	0.00E+00
Total	**6.05E-06**	**3.64E+00**	**6.05E-06**	**3.64E+00**	**2.58E-06**
Δ Dose	2.67E-04 (17)		2.70E-04 (18)		
CCFP	64.28% (2)		64.28% (12)		
ΔCCFP	0.51% (2)		0.51% (13)		
Class 3b LERF	3.83E-08 (9)		3.87E-08 (10)		**Difference**
					4.03E-10 (11)
Delta Class 3b LERF (from 3 in 10 yr base case)	3.07E-08 (14)		3.10E-08 (15)		**Difference**
					3.74E-10 (16)
Delta Class 3b LERF (from 1 in 10 yr base case)	1.28E-08 (19)		1.30E-08 (20)		**Difference**
					2.31E-10 (21)

Notes:

(1) Values taken from Table 5-4.
(2) Values taken from Table 5-5.
(3) Values for all classes except Class 1 and Class 3b are identical to the "without corrosion" values.
(4) Value calculated by summing "without corrosion" frequency and the ΔF value derived from Eqn. 5-7.
(5) Value obtained by multiplying the Class 3b "with corrosion" frequency calculated in this table and the dose for Class 3b listed in Table 5-3.
(6) Value calculated by using the formula for Class 1 listed in Table 5-3.
(7) Value obtained by multiplying the Class 1 "with corrosion" frequency calculated in this table and the dose for Class 1 listed in Table 5-3.
(8) The values in this column are the difference in dose rate (person-rem/yr) between the "with corrosion" and without corrosion" cases.
(9) Value is identical to the Class 3b "without corrosion" frequency listed above.
(10) Value is identical to the Class 3b "with corrosion" frequency listed above.
(11) Value is the difference in the "with corrosion" and "without corrosion" Class 3b LERF values.
(12) Value calculated based upon Eqn. 5-5.

(13) Value is the difference between the "with corrosion" CCFP in this table minus the "with corrosion" CCFP in Table 5-7.
(14) Value is the difference between the "without corrosion" Class 3b LERF in this table minus the "without corrosion" Class 3b LERF in Table 5-7.
(15) Value is the difference between the "with corrosion" Class 3b LERF in this table minus the "with corrosion" Class 3b LERF in Table 5-7.
(16) Value is the difference in the "with corrosion" and "without corrosion" Delta Class 3b LERF (from 3 in 10 yr case) values.
(17) Value is the difference between the "without corrosion" Dose (person-rem/yr) in this table minus the "without corrosion" Dose in Table 5-7.
(18) Value is the difference between the "with corrosion" Dose (person-rem/yr) in this table minus the "with corrosion" Dose in Table 5-7.
(19) Value is the difference between the "without corrosion" Class 3b LERF in this table minus the "without corrosion" Class 3b LERF in Table 5-8.
(20) Value is the difference between the "with corrosion" Class 3b LERF in this table minus the "with corrosion" Class 3b LERF in Table 5-8.
(21) Value is the difference in the "with corrosion" and "without corrosion" Delta Class 3b LERF (from 1 in 10 yr case) values.

Additional corrosion sensitivity cases were developed to gain an understanding of the sensitivity of the results to the key parameters in the corrosion risk analysis. The time for a doubling of the flaw likelihood was adjusted from every five years to every two and every ten years. The failure probabilities for the cylinder and dome and the basemat were increased and decreased by an order of magnitude. The total detection failure likelihood was adjusted from 10% to 15% and 5%. The results are presented in Table 5-10. In every case, the impact from including the corrosion effects is very minimal. Even the upper bound estimates with very conservative assumptions for all of the key parameters yield increases in LERF due to corrosion of only 1.20E-8/yr. The results indicate that even with very conservative assumptions, the conclusions from the "base case" analysis would not change. The tables in Appendix B show the internals of these calculations, which are then summarized in Table 5-10.

Table 5-10 – Summary of Additional Corrosion Sensitivities

Case	Case Description	Age [a]	Containment Breach [b]	Visual Inspection and Non-Visual Flaws [c] [d]	Increase in 3b Frequency (LERF) for ILRT Extension from 3 per 10 years to once per 15 years	
					Total Increase (yr^{-1})	Increase Due to Corrosion (yr^{-1}) [f]
1	Base Case	Doubles every 5 yrs	1% Cylinder 0.1% Basemat	10%	7.47E-10	3.74E-10
2	Age - Upper Bound	Doubles every 2 yrs	Base	Base	1.20E-09	8.28E-10
3	Age - Lower Bound	Doubles every 10 yrs	Base	Base	6.79E-10	3.05E-10
4	Inspection - Upper Bound	Base	Base	15%	9.26E-10	5.53E-10
5	Inspection - Lower Bound	Base	Base	5%	5.98E-10	2.24E-10
6	Breach - Upper Bound	Base	10% Cylinder 1% Basemat	Base	4.11E-09	3.74E-09
7	Breach - Lower Bound	Base	0.1% Cylinder 0.01% Basemat	Base	4.11E-10	3.74E-11
8	Overall Lower Bound [e]	Doubles every 10 yrs	0.1% Cylinder 0.01% Basemat	5%	3.92E-10	1.83E-11
9	Overall Upper Bound	Doubles every 2 yrs	10% Cylinder 1% Basemat	15%	1.20E-08	1.16E-08

Notes:
(a) Step 3 in the corrosion analysis
(b) Step 4 in the corrosion analysis
(c) Step 5 in the corrosion analysis
(d) Percentage value is for the "cylinder" portion of the containment (the basemat is assumed to be uninspectable)
(e) Lower Bound case implements a "5% Cylinder 100% Basemat" visual inspection non-accessibility factor; this differs from what is listed in Table 6-1 in Appendix H of Reference 26. This interpretation is consistent with the other sensitivity cases and the fact that the containment basemat is assumed to be uninspectable.
(f) The “Increase Due to Corrosion” refers to the difference between the “once per 15 year” and “3 per 15 year” ILRT intervals; the corrosion parameters associated with each case are identically applied to the two intervals examined.

5.4.2 Potential Impact from External Events

Evaluation of high winds, external floods, volcanic eruption and other external events in the IPEEE per GL 88-20 were submitted to and reviewed by the NRC. The Staff Evaluation Report concluded that the CGS IPEEE was capable of identifying the most likely severe accidents and severe accident vulnerabilities and the IPEEE met the intent of Supplement 4 to GL 88-20. The IPEEE determined that the recurrence frequency for the maximum tornado wind speed is approximately 1E-07/yr and, as such, maximum wind speed was eliminated as a plant hazard per the Standard Review Plan. Other external events (e.g., external fire, external floods, high winds, volcanic eruption etc.) were considered to be insignificant contributors to severe accidents. The proposed changes should have a negligible effect on the risk profiles from other external events.

The current CGS internal fire and seismic PRA models were created based upon analysis performed in the IPEEE, with periodic updates to reflect the as-built, as-operated plant. Since the current seismic and internal fire PRA models at CGS were not developed using methods that are consistent with the ASME Standard supporting requirements, these models are not deemed to be of sufficient quality to provide numerical estimates of fire and seismic event risk of equal quality to the internal events model; therefore, the methodology used to estimate the risk associated with internal events presented in Sections 5.1 through 5.4 is not replicated for these hazards. However, results from the current CGS internal fire and seismic model results are presented to provide qualitative insights into the risk associated with these hazards, as well as to provide an order of magnitude estimate for the increase in LERF attributable to these hazards.

The methodology used in Sections 5.0 through 5.4 for the calculation of LERF for internal events is applied to generate the value representing the increase in LERF associated with the internal fire hazard (note that the details of the computation process are not presented as they were for internal events). The following tables were generated to display the results of interim steps in the calculation of the increase in LERF:

a) Table 5-11 shows the CDF and LERF values by accident class for FPRA (similar to Table 5-2 for internal events).
b) Table 5-12 shows the release frequency tabulation for FPRA (similar to Table 5-3 for internal events).
c) Table 5-13 shows the FPRA release frequencies for each examined ILRT testing interval (similar to Table 5-4 for internal events).
d) Table 5-14 shows the increase in internal fire LERF for each examined ILRT testing interval (similar to Table 5-5 for internal events).

The methodology used in Sections 5.0 through 5.4 for the calculation of LERF for internal events is applied to generate the value representing the increase in LERF associated with the seismic hazard (note that the details of the computation process are not presented as they were for internal events). The following tables were generated to display the results of interim steps in the calculation of the increase in LERF:

a) Table 5-15 shows the CDF and LERF values by accident class for Seismic PRA (similar to Table 5-2 for internal events).
b) Table 5-16 shows the release frequency tabulation for Seismic PRA (similar to Table 5-3 for internal events).
c) Table 5-17 shows the Seismic PRA release frequencies for each examined ILRT testing interval (similar to Table 5-4 for internal events).
d) Table 5-18 shows the increase in seismic hazard LERF for each examined ILRT testing interval (similar to Table 5-5 for internal events).

Table 5-11 – FPRA Core Damage and LERF by Accident Class

PDS Class	PDS Description	PDS Subclass	Subclass CDF [yr^{-1}]	Subclass LERF [yr^{-1}]
I (Loss of Makeup)	Loss of control and service air sequences with early failure of HPCS, RCIC and RPV depressurization.	A1	0.00E+00	0.00E+00
	Transient and small LOCA sequences with early failure of HPCS, RCIC and RPV depressurization.	A2	2.13E-06	6.35E-08
	Loss of offsite power sequences with failure of high pressure injection and failure to depressurize.	A3	1.23E-08	4.90E-10
	Transients in which high pressure injection fails and RPV depressurization succeeds. Containment heat removal is unavailable.	B0	2.24E-07	0.00E+00
	SBO and loss of inventory makeup (BE: CD at < 4 hrs, BL: CD > 4 hrs)	1G	3.74E-06	1.71E-08
		1H	1.16E-07	4.44E-08
II (Loss of Decay Heat Removal)	Loss of containment heat removal with RPV initially intact; core damage (CD) induced post containment failure	B	2.06E-09	0.00E+00
	Loss of containment heat removal with RPV breached but no initial CD; CD induced post containment failure	D	9.69E-07	0.00E+00
III (LOCA)	Medium LOCA with successful depressurization or large LOCA. Early failure of HPCS and low pressure injection.	C	0.00E+00	0.00E+00
	LOCA sequences with failure of vapor suppression, and assumed failure of injection. Core damage is at low pressure, with containment failed.	E	0.00E+00	0.00E+00
IV (ATWS)	ATWS with vessel intact at time of core uncovery, which indicates high pressure core melt with containment failed.	BA	2.06E-09	1.05E-09

PDS Class	PDS Description	PDS Subclass	Subclass CDF [yr^{-1}]	Subclass LERF [yr^{-1}]
	ATWS with vessel failed at time of core uncovery, which indicates low pressure core melt with containment failed.	BL	4.52E-08	2.04E-08
V (Containment Bypass)	Large or medium LOCA outside containment with failure to isolate the break.	5A	0.00E+00	0.00E+00
	Small LOCA outside containment with failure to isolate the break.	5B	0.00E+00	0.00E+00
VI (Station Blackout)	Station blackout sequences with early failure of HPCS and RCIC.	A1	1.34E-06	1.22E-07
	Station blackout sequences with a stuck-open relief valve, no containment heat removal, but successful injection until containment failure.	A2	0.00E+00	0.00E+00
	Station blackout sequences with initial success of HPCS. HPCS operation is recoverable if ac power is restored. Containment heat removal is unavailable.	B1	8.62E-07	0.00E+00
	Long-term SBO with RCIC operating at time of battery depletion. HPCS is failed.	B2	0.00E+00	0.00E+00
All	**Total**		9.44E-06	2.69E-07

Table 5-12 – EPRI FPRA Release Frequency Tabulation

EPRI Class	Description	Formula (Resultant Frequency)	Resultant Frequency [yr^{-1}]
1	Containment Intact	CDF_{total}-Release $Frequency_{total}$ - $F_{class\ 3a}$ -$F_{class\ 3b}$	2.23E-06
2	Large Containment Isolation Failures	$PROB_{large\ CI}$ * CDF_{total}	7.91E-09
3a	Small Pre-Existing Leak in Containment	$PROB_{Class\ 3a}$ * (CDF_{total} - CDF_{AONL})	6.79E-08
3b	Large Pre-Existing Leak in Containment	$PROB_{Class\ 3b}$*(CDF_{total} - CDF_{AONL})	1.70E-08
7	Severe accident phenomena-induced containment failures (early and late)	Σ(All release categories except intact and BOC from Table 4-5)	7.13E-06
8	Containment Bypass sequences	$CDF_{Class\ V}$	0.00E+00

Table 5-13 – FPRA Accident Class Frequency versus ILRT Frequency

EPRI Accident Class	ILRT Frequency		
	3 per 10 years	1 per 10 years	1 per 15 years
	Frequency [yr^{-1}]	Frequency [yr^{-1}]	Frequency [yr^{-1}]
1	2.23E-06	2.03E-06	1.89E-06
2	7.91E-09	7.91E-09	7.91E-09
3a	6.79E-08	2.26E-07	3.40E-07
3b	1.70E-08	5.66E-08	8.49E-08
7	7.13E-06	7.13E-06	7.13E-06
8	0.00E+00	0.00E+00	0.00E+00
Total	9.45E-06	9.45E-06	9.45E-06

Table 5-14 – CGS FPRA Delta LERF

Risk Metric	ILRT Testing Frequency		
	3 in 10 years	1 in 10 years	1 in 15 years
ΔLERF	N/A	3.96E-08	6.79E-08

Table 5-15 – Seismic Core Damage and LERF by Accident Class

PDS Class	PDS Description	PDS Subclass	Subclass CDF [yr^{-1}]	LERF [yr^{-1}]
I (Loss of Makeup)	Loss of control and service air sequences with early failure of HPCS, RCIC and RPV depressurization.	A1	0.00E+00	0.00E+00
	Transient and small LOCA sequences with early failure of HPCS, RCIC and RPV depressurization.	A2	0.00E+00	0.00E+00
	Loss of offsite power sequences with failure of high pressure injection and failure to depressurize.	A3	7.54E-07	4.82E-08
	Transients in which high pressure injection fails and RPV depressurization succeeds. Containment heat removal is unavailable.	B0	5.37E-08	0.00E+00
	SBO and loss of inventory makeup (BE: CD at < 4 hrs, BL: CD > 4 hrs)	1G	0.00E+00	0.00E+00
		1H	3.54E-09	0.00E+00
II (Loss of Decay Heat Removal)	Loss of containment heat removal with RPV initially intact; core damage (CD) induced post containment failure	B	8.26E-07	0.00E+00
	Loss of containment heat removal with RPV breached but no initial CD; CD induced post containment failure	D	8.13E-11	0.00E+00

PDS Class	PDS Description	PDS Subclass	Subclass CDF [yr^{-1}]	LERF [yr^{-1}]
III (LOCA)	Medium LOCA with successful depressurization or large LOCA. Early failure of HPCS and low pressure injection.	C	0.00E+00	0.00E+00
	LOCA sequences with failure of vapor suppression, and assumed failure of injection. Core damage is at low pressure, with containment failed.	E	0.00E+00	0.00E+00
IV (ATWS)	ATWS with vessel intact at time of core uncovery, which indicates high pressure core melt with containment failed.	BA	7.73E-09	3.64E-09
	ATWS with vessel failed at time of core uncovery, which indicates low pressure core melt with containment failed.	BL	0.00E+00	0.00E+00
V (Containment Bypass)	Large or medium LOCA outside containment with failure to isolate the break.	5A	2.17E-06	2.17E-06
	Small LOCA outside containment with failure to isolate the break.	5B	0.00E+00	0.00E+00
VI (Station Blackout)	Station blackout sequences with early failure of HPCS and RCIC.	A1	5.27E-07	5.89E-09
	Station blackout sequences with a stuck-open relief valve, no containment heat removal, but successful injection until containment failure.	A2	4.71E-08	0.00E+00
	Station blackout sequences with initial success of HPCS. HPCS operation is recoverable if ac power is restored. Containment heat removal is unavailable.	B1	1.44E-07	0.00E+00
	Long-term SBO with RCIC operating at time of battery depletion. HPCS is failed.	B2	0.00E+00	0.00E+00
All	**Total**		4.53E-06	2.23E-06

Table 5-16 – EPRI Seismic PRA Release Frequency Tabulation

EPRI Class	Description	Formula	Resultant Frequency [yr^{-1}]
1	Containment Intact (2)	CDF_{total}-Release $Frequency_{total}$-$F_{class\ 3a}$-$F_{class\ 3b}$	8.68E-07
2	Large Containment Isolation Failures (1)	$PROB_{Large\ CI}$*CDF_{total}	3.80E-09
3a	Small Pre-Existing Leak in Containment	$PROB_{Class\ 3a}$ * (CDF_{total} - CDF_{AONL})	1.19E-08
3b	Large Pre-Existing Leak in Containment	$PROB_{Class\ 3b}$*(CDF_{total} - CDF_{AONL})	2.97E-09
7	Severe accident phenomena-induced containment failures (early and late) (2)	F_{Class7} = CDF_{CFL}+CDF_{CFE} (See Table 4-5)	1.48E-06
8	Containment Bypass sequences	$CDF_{Class\ V}$	2.17E-06

Table 5-17 – Seismic PRA Accident Class Frequency versus ILRT Frequency

EPRI Accident Class	ILRT Frequency		
	3 per 10 years	1 per 10 years	1 per 15 years
	Frequency [yr^{-1}]	Frequency [yr^{-1}]	Frequency [yr^{-1}]
1	8.68E-07	8.33E-07	8.09E-07
2	3.80E-09	3.80E-09	3.80E-09
3a	1.19E-08	3.96E-08	5.94E-08
3b	2.97E-09	9.90E-09	1.49E-08
7	1.48E-06	1.48E-06	1.48E-06
8	2.17E-06	2.17E-06	2.17E-06
Total	4.54E-06	4.54E-06	4.54E-06

Table 5-18 – Seismic PRA Delta LERF

Risk Metric	ILRT Testing Frequency		
	3 in 10 years	1 in 10 years	1 in 15 years
ΔLERF	N/A	6.93E-09	1.19E-08

RG 1.174 provides NRC recommendations for using risk information in support of applications requesting changes to the license basis of the plant. The Regulatory Guide 1.174 acceptance guidelines are used here to assess the ILRT interval extension. Those acceptance guidelines are presented in Figure 5-1 (which is excerpted from RG 1.174). Table 5-19 summarizes the results for the external event LERF increase analysis performed at CGS.

Figure 5-1 – RG 1.174 Acceptance Guidelines for LERF

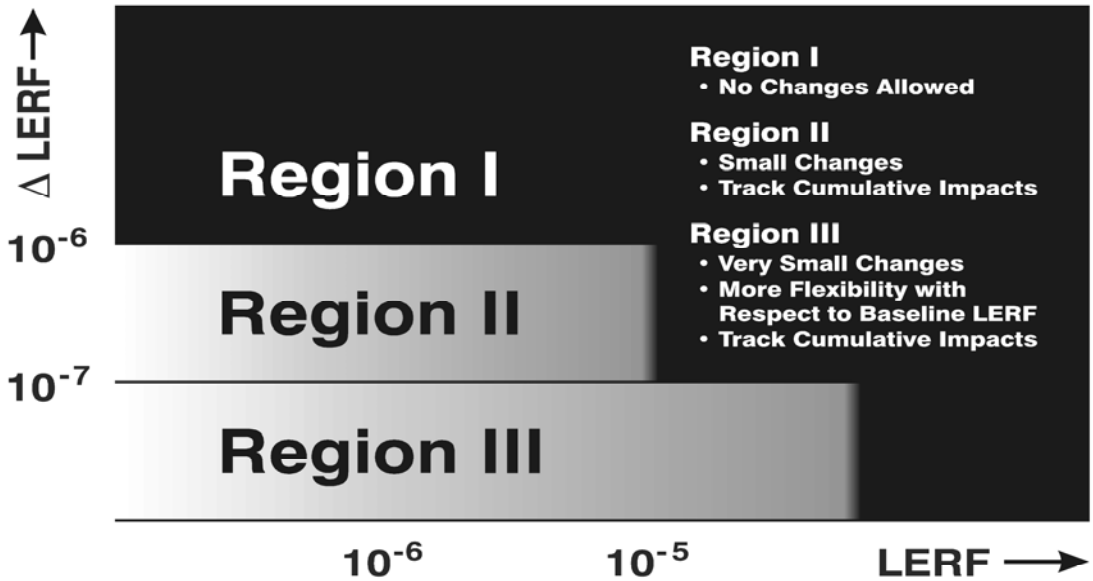

Table 5-19 – External Events LERF Summary

Hazard	LERF (yr^{-1})	ΔLERF (yr^{-1}) (3)
Internal Events	3.28E-07	3.07E-08
Fire	2.69E-07	6.79E-08
Seismic	2.23E-06	1.19E-08
Total	2.83E-06	1.10E-07
Threshold	1.00E-05 (1)	1.00E-06 (2)

(1) Threshold based upon maximum LERF for Region II in Figure 5-1.
(2) Threshold based upon maximum ΔLERF for Region II in Figure 5-1.
(3) CGS internal fire and seismic model results are presented to provide qualitative insights into the risk associated with these hazards, as well as to provide an order of magnitude estimate for the increase in LERF attributable to these hazards.

As can be seen from Table 5-19, none of the ΔLERF values in the internal events, fire, or seismic hazard groups exceeds 1.0E-07/yr; these increases would, therefore, be classified as being "very small" per Figure 5-1. If one sums the internal events, fire, and seismic hazard group values, one sees that the increase in LERF is 1.10E-7/yr; per Regulatory Guide 1.174 (and Figure 5-1), this is a "small change" (increase) in LERF, given that the baseline LERF value of 2.83E-6/yr for this bounding case is between 1E-6/yr and 1E-5/yr.

The large margin between summed LERF value and the threshold provides assurance that the small risk increase associated with this application is acceptable when one accounts for the significant level of uncertainty associated with the fire and seismic PRA model results.

5.4.3 Impact of 2009 Peer Review Finding 2-2

Finding 2-2 from the 2009 CGS PRA Peer Review (Reference 33) states that:

> *The number of plant-specific demands on standby components was mainly documented for the maintenance rule and MSPI components. Tier 3 PSA documents for PSA-2-DA-0002 show the details. Estimates based on the surveillance tests and maintenance acts as described in this SR should be performed even though the major components have been included in the MSPI data.*

This finding has been addressed; however, the resolution has not been incorporated into the PRA model of record. Therefore, a sensitivity was performed to quantify the impact of this finding.

Resolution of F&O 2-2 impacts the following component failure modes:

- C---W2 (compressor fails to start)
- C---W4 (compressor fails to run)
- FN--R3 (fan fails to start)
- FR--W4 (fan fails to run)
- AHUS---S3 (air handling unit fails to start)
- AHUR---W4 (air handling unit fails to run).

A sensitivity study was performed by replacing the baseline model failure data with data that was informed by the surveillance tests and maintenance acts as described in the associated SR. A quantification was performed with the modified failure data and the results for the increase in LERF were computed and compared with the baseline model result.

The increase in LERF is computed based upon Eqn. 5-3 and Eqn. 5-4. The results are summarized in Table 5-20 (the parameters in the table are described below).

1. CDF_{AONL} – Portion of CDF that will always or never go to LERF per Eqn. 5-2.
2. CDF_{Total} – Total CDF (for the sensitivity case) per Eqn. 5-3.
3. (CDF_{Total} – CDF_{AONL}) – Item 1 subtracted from Item 2 per Eqn. 5-3.
4. $F_{Class3b}$ – Frequency of Class 3b release per Eqn. 5-3.
5. $LERF_{3in10}$ – Sensitivity LERF for base (3 ILRT tests in 10 years) case (value is identical to Item 4.
6. $LERF_{1\ in\ 15}$ – Sensitivity LERF for proposed ILRT extension interval (1 ILRT test every 15 years).
7. $\Delta LERF_{SENS}$ – LERF increase for the sensitivity case (per Eqn. 5-4).
8. $\Delta LERF_{BASE}$ – LERF increase for the model of record case (per Eqn. 5-4).

9. $\Delta LERF_{SENS}$ - $\Delta LERF_{BASE}$ – Difference in the LERF increase from the sensitivity case minus the model of record case.

Table 5-20 – F&O 2-2 Sensitivity Study

Parameter	Result (yr^{-1})
CDF_{AONL}	2.95E-06
CDF_{Total}	6.81E-06
CDF_{Total} - CDF_{AONL}	3.86E-06
$F_{Class3b}$	8.89E-09
$LERF_{3in10}$	8.89E-09
$LERF_{1\ in\ 15}$	4.44E-08
$\Delta LERF_{SENS}$	3.55E-08
$\Delta LERF_{BASE}$	3.07E-08
$\Delta LERF_{SENS}$ - $\Delta LERF_{BASE}$	4.84E-09

The sensitivity case LERF increase for the ILRT interval extension compared to the model of record base case LERF increase is less than 5.0E-9/yr. This numerical difference shows that the quantitative increase associated with the resolution of Finding F&O 2-2 is insignificant for this application.

6. Results

The results from this ILRT extension risk assessment for CGS are summarized in Table 6-1.

Table 6-1 – ILRT Extension Summary

Class	Dose (person-rem)	3 in 10 years		1 in 10 years		1 in 15 years	
		Freq [yr^{-1}]	Person-rem/yr	Freq [yr^{-1}]	Person-rem/yr	Freq [yr^{-1}]	Person-rem/yr
1	6.46E+01	2.16E-06	1.40E-04	2.07E-06	1.34E-04	2.01E-06	1.30E-04
2	2.01E+06	5.06E-09	1.02E-02	5.06E-09	1.02E-02	5.06E-09	1.02E-02
3a	6.46E+02	3.07E-08	1.98E-05	1.02E-07	6.60E-05	1.53E-07	9.91E-05
3b	6.46E+03	7.67E-09	4.95E-05	2.55E-08	1.65E-04	3.83E-08	2.48E-04
7	8.87E+05	3.65E-06	3.23E+00	3.65E-06	3.23E+00	3.65E-06	3.23E+00
8	2.01E+06	1.99E-07	4.00E-01	1.99E-07	4.00E-01	1.99E-07	4.00E-01
Total	N/A	6.05E-06	3.64E+00	6.05E-06	3.64E+00	6.05E-06	3.64E+00
ILRT Dose Rate from 3a and 3b							
ΔTotal Dose Rate	From 3 Years	N/A		1.62E-04 (1)		2.77E-04 (2)	
	From 10 Years	N/A		N/A		1.16E-04 (3)	
Δ % Dose Rate	From 3 Years	N/A		0.00444% (4)		0.00761% (5)	
	From 10 Years	N/A		N/A		0.00318% (6)	
3B Frequency LERF							
ΔLERF	From 3 Years	N/A		1.79E-08 (7)		3.07E-08 (7)	
	From 10 Years	N/A		N/A		1.28E-08 (8)	
CCFP%							
ΔCCFP (%)	From 3 Years	N/A		0.30% (7)		0.51% (7)	
	From 10 Years	N/A		N/A		0.21% (9)	

Notes:

(1) Values based upon the difference between the sum of the dose rates (in person-rem/yr) for Class 3a and Class 3b for the "1 in 10 year" case minus the sum of the dose rates for Class 3a and Class 3b for the "3 in 10 year" case.

(2) Values based upon the difference between the sum of the dose rates (in person-rem/yr) for Class 3a and Class 3b for the "1 in 15 year" case minus the sum of the dose rates for Class 3a and Class 3b for the "3 in 10 year" case.

(3) Values based upon the difference between the sum of the dose rates (in person-rem/yr) for Class 3a and Class 3b for the "1 in 15 year" case minus the sum of the dose rates for Class 3a and Class 3b for the "1 in 10 year" case.
(4) Values based upon the formula [ΔTotal Dose $Rate_{1in10yr}$ / Dose $Rate_{3in10yr}$].
(5) Values based upon the formula [ΔTotal Dose $Rate_{1in15yr}$ / Dose $Rate_{3in10yr}$].
(6) Values based upon the formula [ΔTotal Dose $Rate_{1in15yr}$ / Dose $Rate_{1in10yr}$].
(7) Values taken from Table 5-5.
(8) Value calculated from inputs in this table based upon the formula [$Freq_{3B\text{-}1in15}$ - $Freq_{3B\text{-}1in10}$].
(9) Value calculated from information in Table 5-5 based upon the formula [$CCFP_{1in15} - CCFP_{1in10}$].

7. Conclusions

Based on the quantitative results and the sensitivity calculations presented in Sections 5 and 7, the following conclusions regarding the assessment of the plant risk are associated with extending the Type A ILRT test frequency to fifteen years:

1. Reg. Guide 1.174 (Reference 4) provides guidance for determining the risk impact of plant-specific changes to the licensing basis. Reg. Guide 1.174 defines very small changes in risk as resulting in increases of CDF below 10^{-6}/yr and increases in LERF below 10^{-7}/yr. Since the ILRT does not impact CDF, the relevant criterion is LERF. The increase in LERF resulting from a permanent change in the Type A ILRT test interval from three in ten years to one in fifteen years is very conservatively estimated as 3.07E-08/yr using the EPRI guidance as written,. As such, the estimated change in LERF is determined to be "very small" using the acceptance guidelines of Reg. Guide 1.174.

2. The ΔLERF values associated with the ILRT interval change to 15 years for each of the hazard groups examined (internal events, fire, or seismic) is less than 1.0E-7/yr; these increases would, therefore, be classified as being "very small" per Regulatory Guide 1.174. If one sums the internal events, fire, and seismic hazard group values, one sees that the increase in LERF is 1.10E-7/yr; per Regulatory Guide 1.174 this is a "small change" (increase) in LERF, given that the baseline LERF value of 2.83E-6/yr for this bounding case is between 1E-6/yr and 1E-5/yr. The large margin between summed LERF value and the threshold provides assurance that the small risk increase associated with this application is acceptable when one accounts for the significant level of uncertainty associated with the fire and seismic PRA model results.

3. 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, is 2.77E-4 person-rem/yr (a 0.00761% increase). EPRI Report No. 1009325, Revision 2-A states that a very small population dose is defined as an increase of $\leq$ 1.0 person-rem per year or $\leq$1% of the total population dose, whichever is less restrictive for the risk impact assessment of the extended ILRT intervals. Moreover, the risk impact when compared to other severe accident risks is negligible.

4. The increase in the conditional containment failure frequency from the three in ten year interval to one in fifteen year interval is 0.51%. EPRI Report No. 1009325, Revision 2-A

states that increases in CCFP of less than or equal to 1.5 percentage points are very small. Therefore this increase judged to be very small.

5. Since containment overpressure is not required in the CGS design basis or the CGS PRA model to support ECCS performance to mitigate accidents at CGS, the effect of the ILRT extension on containment overpressure need not be addressed.

Therefore, based upon the above factors, the overall risk of increasing the ILRT interval to once per 15 years is considered to be non-significant, since it represents a small change to the CGS risk profile.

8. References

The following is a list of references that were used in this guidance document. It should be noted that several of the references are not "called out" in the text of this evaluation; however, to maintain consistency with the reference numbers in the template provided in Reference 26, these references were retained in the document and can be viewed as being bibliographic in nature.

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A. Appendix A – PRA Model Technical Adequacy

The CGS Model Version 7.2.1 model update is the most recent evaluation of the risk profile at CGS for internal event (including internal flooding) challenges. The CGS PRA modeling is highly detailed, including a wide variety of initiating events, modeled systems, operator actions, and common cause events. The PRA model quantification process used for the CGS PRA is based on the event tree/fault tree methodology.

It was concluded that the CGS PRA quality is sufficient to support TSTF-425 (References 45, 46, and 47); Section A.3 Item 5 contains more information on the applicability of the TSTF-425 assessment of PRA quality to the ILRT submittal.

CGS employs a multi-faceted approach for establishing and maintaining the technical adequacy and plant fidelity of the PRA model. This approach includes both a proceduralized PRA maintenance and update process and the use of independent peer reviews. The following information describes this approach as it applies to the CGS PRA.

A.1 PRA Maintenance and Update

The CGS risk management process ensures that the PRA model remains an accurate reflection of the as-built and as-operated plant. This process is defined in the CGS PRA model maintenance and configuration control program in accordance with the governing procedure, SYS-4-34 (Reference 42). The procedure delineates the responsibilities and guidelines for updating the full power internal events PRA model. It also defines the process for implementing regularly scheduled reviews and interim PRA model updates, for tracking issues identified as potentially affecting the PRA models (e.g., due to changes in the plant, errors or limitations identified in the model, industry operating experience), and for controlling the model and associated computer files. To ensure the current PRA model remains an accurate reflection of the as-built, as-operated plants, the following activities are routinely performed:

- Design changes and procedure changes are reviewed for their impact on the PRA model.
- Maintenance unavailabilities are captured, and their impact on Core Damage Frequency (CDF) is trended.
- Plant specific initiating event frequencies, failure rates, and maintenance unavailabilities are updated periodically.

In addition to these activities, CGS risk management procedures provide the guidance for particular risk management, PRA quality, and maintenance activities. This guidance includes:

- Documentation of the PRA model, PRA products, and bases documents.
- The approach for controlling electronic storage of risk management products including PRA update information, PRA models, and PRA applications.
- Guidelines for updating the full power, internal events PRA models for CGS.

- Guidance for use of quantitative and qualitative risk models in support of the Work Control Process Program for risk evaluations for maintenance tasks (corrective maintenance, preventive maintenance, minor maintenance, surveillance tests and modifications) on systems, structures, and components (SSCs) within the scope of the Maintenance Rule (10CFR50.65(a)(4)).

A.2 Plant Changes not yet incorporated into the PRA Model

A review of plant modifications and procedure changes was performed. Plant EOPs have been modified to implement early containment vent if primary containment pressure reduction is required to maintain adequate core cooling during an extended loss of ac power. The RCIC backpressure trip signal is overridden; RCIC can maintain operation while drawing suction from the CST or from the suppression pool for suppression pool temperatures up to 240 degrees-F. These procedural features significantly improve the operational availability of RCIC. This procedural enhancement has not been credited in the applicable SBO accident sequences, and a self-assessment observation has been made to address this enhancement in a future PRA update

There are several modifications with PRA impact that are scheduled to be implemented in the upcoming refueling outage. The evaluation of these planned plant changes is presented in Table A-1. One change would improve the risk profile as implemented and two would have minimal quantitative impact if implemented. Based upon this analysis, it can be concluded that the current PRA model is representative (with a conservative bias) with respect to the current plant configuration and also with respect to the ILRT extension request calculations.

A.3 PRA Technical Adequacy for the Current Model of Record

The CGS PRA model of record is Revision 7.2.1. Revision 7.2.1 is a minor model update based upon Revision 7.2. The Columbia PRA meets Capability Category II of Addendum A of the ASME ANS Standard (Reference 32), as clarified by RG 1.200, Rev. 2 (Reference 31). All ASME Standard SRs currently meet or exceed the Capability Category II.

The following is a brief history of the CGS PRA model and associated peer reviews, as well as a summary of the modeling modifications that were performed to create Revision 7.2 (Reference 17) and Revision 7.2.1 (Reference 44).

1. In 2004 the Columbia PRA received a peer review (Reference 34) against the Capability Category II requirements Addendum A of the 2002 ASME PRA Standard. The Rev. 7.1 PRA resolved all of the 2004 peer review F&Os with the exception of one D-level F&O, HR-D7-1, which the Rev. 7.2 PRA has now resolved. The results of this peer review were superseded by the 2009 peer review (discussed in Item 2 below).

2. In 2009, the Columbia PRA received a peer review (Reference 33) against the ASME / ANS PRA Standard, as clarified by Regulatory Guide 1.200, Rev. 2. All F&O Findings from the 2009 Peer Review have been resolved. Table A-2 summarizes the resolution

of the findings from the 2009 peer review associated with supporting requirements that did not meet or exceed Capability Category II.

3. The CGS plant design has been reviewed for permanent plant changes, such as design or operational practices. For the Rev. 7.2 PRA update, those changes that were found to have an impact on the PRA model were incorporated into the baseline PRA model, as applicable:

   a) The Group 1 nuclear steam supply shutoff system (MSIV) actuation set point changed from Reactor Level 2 to Level 1. This design change impacts the plant transient response and PRA in the following manner:

      - Power conversion system (PCS) availability – Following a plant transient and loss of reactor feedwater, the HPCS and RCIC systems will receive a signal to start when an "A" actuation signal is generated when reactor level reaches Level 2. If HPCS or RCIC start, reactor Level 1 will not be reached and the MSIVs will initially remain open, which supports decay heat removal through the PCS. However, an "A" actuation signal trips non-essential power supplies, including power to the main steam tunnel coolers. A heat-up of the main steam tunnel leads to MSIV closure and loss of PCS. Therefore, this plant design change produced no material change in the availability of PCS from a PRA perspective, and no change in the PRA results.
      - Plant operator response to ATWS – The change of the MSIV actuation set point to Level 1 potentially improves the timing for operators to bypass the MSIV low level interlock. The RPV Control (ATWS) response is directed from EOP 5.1.2 "RPV Control (ATWS)". One of the actions is to reduce RPV water level to minimize power production. This initially occurs to below the feedwater sparger which generally would NOT lead to MSIV closure. If the containment and RPV conditions cannot be controlled, RPV level must be lowered further. The MSIV interlock on low RPV water level is directed to be bypassed in parallel with tasks associated with lowering RPV water level. Since bypass of the MSIV interlock is one of the immediate control room activities that are undertaken to cope with the plant challenges, no significant change in the human error probability is judged to apply. Therefore, no change was made in the error probability for human failure event MS-H-ATWBYP-H3XX, "Operator fails to bypass MSIV Interlock."

   b) Containment vent without ac and dc power available - A procedure has been implemented to vent containment without AC and DC power available. Operators locally manipulate valves to vent containment from the drywell or wetwell. This operational enhancement has been added to CGS PRA Rev. 7.2.

4. In PRA minor model release Revision 7.2.1, selected dependent HEP values were modified for use in the non-LERF Level 2 release term quantification and separate recovery files were constituted to implement these recoveries. The revisions associated with this model release had no impact on the CDF or LERF modeling or quantitative solutions; therefore, the release of this model version had no impact on the assessed technical adequacy of the PRA with respect to the ASME Standard.

5. The description of the PRA technical adequacy for this ILRT application (including resolutions to the F&Os presented in Table A-2) is consistent with that presented in the TSTF-425 (risk informed surveillance interval) risk assessment incorporated into the TSTF-425 license amendment request (LAR). The TSTF-425 LAR for Columbia was approved by the NRC on November 3, 2016 (References 45, 46, and 47).

Table A-1 – Plant Changes not yet Incorporated into the PRA Model

Change Document	Observation	Recommendation	Impact
EC-14786	Changing power source to RRA-FN-21, and RRA-FN-9 so that the steam tunnel cooling fans continue to operate under the F or A alarm trip logic during accident conditions. The load centers that the fans are fed from now, E-MC-7C and E-MC-8C are load shed given an FA signal, and the load shed will result in a loss of steam tunnel cooling without this change.	Revise the power supplies for the steam tunnel fans per EC-14786. This modification will mean that MSIV's can remain open, given the occurrence of an FA LOCA signal.	Implementation of this modification would improve the ability to maintain the condenser as a heat sink in certain scenarios; implementation of a model change for this item would improve the risk profile. Therefore, the current model is conservative with respect to this item.
EC-12954	In this modification Electrical Panel E-PP-7AA (located in the control room) is being split into two panels. the right panel will become a safety related panel E-PP-7AA and the left panel will become the Non Safety Related panel E-PP-US/D. Non Safety related loads presently connected to E-pp-7AA will be moved to E-PP-US/D. Some Safety Related Loads will be rearranged on E-PP-7AA. Panel E-PP-US/D will be re-feed from the spare fuse disconnect from panel E-PP-US.	Revise FT modeling as applicable.	The modification modifies the human factors associated with the controls used in certain modeled HFEs. This rearrangement of components may have a positive effect on the ability to successfully perform some of these HEPs. However, these potential improvements are deemed to be minimal as to their effect on the human error probabilities for those events.

Change Document	Observation	Recommendation	Impact
EC-14179	Replacement of the existing ASD Glycol temperature switches (GY-TS-10A1, GY-TS-10A2, GY-TS-10B1, and GY-TS-10B2) with a similar type that would allow replacement with the system in service and aids in eliminating the consequences of tripping the ASD drives that could limit the RRC pumps to less than or equal to 51Hz, approximately 90% power. Replace the Foxboro conductivity analyzers (GY-CI-10A1, GY-CI-10A2, GY-CI-10B1, and GY-CI-10B2) along with the conductivity/resistivity probes (GY.CE-10A1, GY-CE-10A2, GY-CE-10B1, and GY-CE-10B2). Provide interfaces into eDNA for proper indication of the glycol temperature and conductivity for monitoring and trending purposes. The new eDNA points will be available to the operator in the MCR. Reconfigure power between RRC-IMD-ASD1A/2 and RRC-IMD-ASD1B/1 to ensure a runback of both pumps to 51 Hz or 90% power is achieved rather than Single Loop Operation (SLO). Bypass the high temperature trip of the glycol switches to prevent tripping of the drives. This is accomplished by making the currently installed jumpers permanent. Relocate the isolation and check valves for the adjustable speed drive (ASD) glycol coolant pumps per vendor recommendations. Install new Temperature Indicators (GY-TI-10A1, GY-TI-10A2, GY-TI-10B1, GY-TI-10B2)	Evaluate these proposed changes and incorporate any changes that have been implemented that affect the PRA model.	The PRA function for the recirculation pumps is to trip in the event of an ATWS. This function is not affected by this modification. There may be some impact of this modification on initiating event frequency (improved reliability for control and runback logic). However, this impact is deemed to have minimal impact on the overall risk profile of the plant.

Table A-2 – Resolution of CGS Internal Events Peer Review Findings not Meeting Category II

F&O [Ref. 33]	2009 SR	Observations	Resolution [Ref. 43]
1-10	IE-C14	HPCS notebook does not include the Surveillance Test for HPCS-V-4. Additionally, the screening for HPCS in the ISLOCA Section of the Initiating Event Notebook (appendix E) does not account for the possibility of ISLOCA during testing of this valve. A possible scenario is, prior to V-4 test, the injection Check Valve V-5 has failed open, and once the test has completed, V-4 does not close and V-24 fails (may be CC). The result is ISLOCA to low pressure piping. OSP-HPCS/IST-Q701 lists V-4 as being tested quarterly. V-23 is open during the test, given reactor is at pressure. (This F&O originated from SR IE-C14)	To resolve this finding, an ISLOCA assessment was performed for the HPCS system, including consideration of HPCS-V-23, HPCS-V24, and the inservice testing of HPCS-V-4 and as discussed in the finding. Documentation of this assessment was added to Appendix E, ISLOCA Initiating Event Frequency, of the initiating events notebook.
1-14	IE-C14	ISLOCA analysis applies a conditional probability of valve closure from NSAC-154, but applies this to NUREG/CR-6928 data. See IE notebook, Table E-1. Application of The NSAC data does not appear appropriate when applied to NUREG/CR-6928. The new valve failure data, such as check valve internal rupture, is not applicable to the older factors for valve re-closes. For example, CV closes following pipe failure (0.01) is based on older data, while the NUREG/CR-6928 data for check valve rupture would typically have screened failures where the check valve stuck open (fails to close), but later reclosed. ISLOCA is risk significant, and the factors affect multiple sequences. (This F&O originated from SR IE-C14)	The ISLOCA event tree was modified to address this peer review finding. The ISLOCA analysis was revised to replace older valve failure data published by NSAC-154 with the latest valve failure data published in NUREG/CR-6928, wherever newer data was available. A review of NUREG/CR-5124 revealed that the conditional probability of check valve closure (event tree node CV) is applicable only to scenarios in which a testable check valve is held open due to reverse air flow to the controller. The 0.01 credit had minimal impact on the ISLOCA sequence cutsets, as the significant check valve failures are leakage and rupture. Therefore, event tree node CV was removed from the ISLOCA event tree. Event tree node SML (small leak through the high/low pressure interface) is moved to an earlier position in the event tree, as leaks through the high/low pressure boundary are judged to be isolable (the 900-pound MOVs that are present at the boundaries are judged to be capable of closing against a leak). The model retains the assumption that MOVs would not likely close if a piping rupture and interface rupture were to occur, per NUREG/CR-5124 guidelines. Also, the event tree node ISOVAV (early isolation of the ISLOCA) probability has been changed to a 0.1 based on documentation provided with the CGS SPAR model. From the CGS SPAR model documentation: Without doing detailed pressure capacity calculations and detailed modeling of the expected internal pressures and temperatures expected in the connected systems, it is impossible to predict the location of potential ruptures. Even with detailed calculations and modeling, precise rupture locations are impossible to identify. Nevertheless, some general observations can be made based on the GI-105 research. For most situations the RHR heat exchanger, and pump suction pipe are the components with the lowest pressure capacities. Generally, these components are positioned within the systems such that one or more valves are available to isolate a rupture, should an ISLOCA occur at these locations. However, it is possible that if the pressure isolation interface were to fail, that either the available valves would not successfully isolate the rupture, or the rupture could occur in a location that cannot be isolated. To account for these possibilities, a generic 10% probability is assumed that if

F&O [Ref. 33]	2009 SR	Observations	Resolution [Ref. 43]
			a rupture were to occur, it cannot be isolated. This 10% probability for the rupture being non-isolable can be considered to be a reasonable estimate for a number of reasons. First, virtually every rupture location examined as part of the GI-105 research program was found to be potentially isolable. The pipe and other components (e.g., pump suction pipe and RHR heat exchangers) that are most susceptible to over-pressure induced rupture, are located "deeper" within the connected system such that a number of valves are typically available for isolating the rupture. Further, the typical failure mode postulated in the ISLOCA analysis for motor operated valves is spurious operation. The few actual instances of this observed in the operating experience were all recoverable from the control room. However, one factor that affects the ability to isolate the rupture is local accessibility. If a rupture were to occur, the resulting local environment would likely preclude access to the immediate vicinity. Therefore, if local access was necessary, and if the potential isolation valves were located close to the rupture then isolation would be unlikely. Again, the research performed to support resolution of GI-105 included an assessment of induced flooding and the resultant environment. That work concluded these effects would not significantly affect the ISLOCA risk. Therefore, the non-isolable ruptures are assumed to compose 10% of the potential ISLOCA ruptures. The accident sequence notebook was updated to reflect all of these changes to the ISLOCA model.
1-23	HR-D2	The quantification of pre-initiating events using 3 surrogate events to represent all pre-initiating events does not provide an accurate assessment of each HEP, taking into account plant specific or component specific attributes. Appendix A.4 for example, provides a "generic" assessment of miscalibration with dependencies, without actually including the specific attributes for the procedure affecting events it is applied. For pre-initiator failure to restore events, the use of the surrogate event does not account for post-maintenance testing, operations walkdowns, and when the system may be operated again. For pre-initiator miscalibration, the surrogate event does not represent the plant specific calibration procedures. In Appendix A.4, the following is provided in the generic analysis "The results of these evaluations indicate that, depending on the methods used to verify the adequacy of the calibration and the assumptions used in the quantitative evaluation, there can be substantial variation in the common cause miscalibration error probability." This statement is true, which is why plant-specific attributes are needed for this analysis. Numerous Pre-Initiating Events in all three categories are risk-significant, based on table E-2 of the QU notebook. Comparison with other PRAs shows that variation between component/action specific HEPs is expected, and the range of differences from one component to the next can be several orders of magnitude. For miscalibrations, for example, depending on whether the miscalibration can be quickly recognized or whether there is a second check on the calibration can greatly affect the results. Variation in dependent failures and failure to restore is equally large within a PRA. CGS provided discussion on this F&O suggesting the important pre-initiating events were represented by the "representative" actions, and the procedures for each action were similar. The following procedures were reviewed for this follow-up: Representative Procedures:	Procedure-specific pre-initiator HEP calculations were developed for the top three pre-initiator human failure events when sorted by RAW and the top three pre-initiator human failure events when sorted by Fussell-Vesely based on the CGS Rev. 7.0 Level 1 PRA model results. This resulted in a total of five pre-initiator human failure events for which to perform procedure-specific HEP calculations. (Note - Five are evaluated, rather than six, because the top pre-initiator human failure event when sorted by RAW was also the top pre-initiator action when sorted by F-V). Section 3.0a and Appendix A.0 were added to the HRA Notebook to document the updated procedure specific pre-initiator HEP calculations. The five revised pre-initiator HEPs were subsequently incorporated into the CGS HRA Calculator file.

F&O [Ref. 33]	2009 SR	Observations	Resolution [Ref. 43]
		SOP-CN-FILL (for CN-HUMNTK--1X3XX), ISP-LPCS/RHR-X301 (for LPSHUMNFIS-4XLL) Significant HEP Procedures: Calibration: ISP-RCIC-Q901 (HEP: RCIHUMNPS13AX3LL), 10.27.86 (HEP: RCIHUMNPS--6X3LL) Restoration: OSP-SW/IST-Q702 (HEP: SWB-XHE-RE-RHRSW), OSP-SW/ISP-Q701 (HEP: SWA-XHE-RE-RHRSW), SOP-COLDWEATHER-OPS (HEP: SW-HUMNV218-X3LL), OSP-HPCS/IST-Q701 (HEP: HPC-XHE-RE-MAINT) Based on a review and comparison of the representative procedures versus the procedures for significant HEPs, it is clear the procedures, associated critical steps, and verification steps are significantly different. (This F&O originated from SR HR-D2)	

F&O [Ref. 33]	2009 SR	Observations	Resolution [Ref. 43]
1-3	HR-G3	Analysis for HEPs apply low stress to post-accident situations for almost all HEPs, even though the criteria in NUREG-/CR-1278 recommends High Stress especially when the time window is short. See HPSHUMN-SP-H3LL, OP-SW-PMP, SLC-XHE-FO-LLVCT and others. Supplemental guidance was provided by CGS personnel as a result of this issue. The CGS argument included an argument that there was not extensive use of simulator training prior to the development of NUREG/CR-1278, and that this training affects the application of stress to simple actions where training occurs. A second set of justification was provided, with discussion that basically justified moderate or low stress would be appropriate, given enough training for the operators. Review of this new guidance does not provide sufficient justification for the revised application of NUREG/Cr-1278 Guidance. Two points are important to this finding: a) stress will affect actions occurring during an accident in comparison to non-accident actions making the actions less reliability, and b) Stress is based on an "overall sense of being pressured and/or threatened in some way with respect to what they are trying to accomplish." Training cannot fully remove the treat or pressure during an actual event. Stress factors assumed to be nominal are also in the Level 2 model and flooding model for short duration HEPs. NUREG/CR-1278 recommends applying optimum stress to activities such as maintenance and calibration activities, reading an annunciator light, or scheduled readings in the control room. On the other hand, Page 17-7 states that 'In general, situations that impose time pressure on the performers are classified as heavy task load situations.' In almost all of the Post-Initiator HEPs where optimal stress is assumed, time is a factor with Core Damage occurring between 30 minutes and an hour. This time stress is typically modeled as high stress in HRA using NUREG/CR-1278. Numerous HEPs where this is applied are risk-significant. Discussions with CGS staff indicated that the low stress was applied to actions that are relatively simple. However, since this simple actions are already low if failure rate, the stress factor is still applicable in order to differentiate between a simple action performed as a routine action, and a simple action performed in order to avoid core damage. Nominal stress is also applied for Level 2 actions, such as failure to provide injection after the control rods fail (10 minute window) just prior to core damage. The general rules for this as applied by CGS do not appear consistent with NUREG/CR-1278 or other PRAs reviewed for this issue. (This F&O originated from SR HR-G3)	As part of the Rev. 7.2 PRA update performed in 2014, the assignments of stress levels were reviewed for all CGS post-initiator human failure events, and all post-initiator human failure events now utilize the stress levels recommended by the HRA Calculator. On a case-by-case basis the next higher stress level, above the stress level recommended by the HRA Calculator was selected, based on HRA analyst judgment. In this manner, the full intent of F&O 1-3 has been resolved. By utilizing the HRA Calculator, the stress levels assigned to the CGS HFEs follow the NUREG/CR-1278 guidelines, including addressing the impact to stress levels from time pressure.

F&O [Ref. 33]	2009 SR	Observations	Resolution [Ref. 43]
1-33	HR-I2	HEPs are calculated using the HEP calculator, and are realistically treated in most cases consistent to the Applicable procedures. However, documentation on several actions was not found in the HRA notebook: 1) L2-HUMN-MUPHNOWS 2) L2-HUMN-RCVR-SYS Note this is just a sampling of the notebook, so others may also be missing. L2-HUMN-MUPHNOWS is mentioned in Section C.16 of the LERF notebook, but not in the HRA notebook. Based on discussion with CGS, this HEP is set to 1.0 based on engineering judgment. L2-HUMN-RCVR-SYS is listed as using the HRA calculator, but is set to 0.9 based on engineering judgment. L2-HUMN-RCVR-SYS is risk-significant. Based on the Internal Events and Flooding HRA review, other HEPs are likely missing in the documentation (HRA notebook) that is credited in the analysis). (This F&O originated from SR LE-C2)	This finding was resolved by adding Level 2 human failure events to the HRA Calculator and the summary Table 5.1-2 of the HRA Notebook. Also, as documented in Table C.4.7-2 of the CGS Level 2 notebook, the basis for the screening HEP for L2-HUMN-RCVR-SYS is engineering judgement.
1-42	HR-I2	HEP Dependency Analysis included in Appendix D of the HRA notebook does not included in the Level 2 Analysis. Level 2 modeling includes new HEPs not in the Level I HRA. LERF may be underestimated if dependent HEPs are not included along with the independent HEPs. (This F&O originated from SR LE-C8)	To resolve this peer review finding, a Level 2 HEP dependency analysis was performed and documented in Section 5 and Appendix D of the HRA Notebook.
1-43	LE-D4	HRA events RHRHUMN-V--803XX and 903XX are included in the ISLOCA analysis but do not include dependency considerations. See the top cutset in Appendix D, dependency analysis. Based on discussion with CGS, the cutset with 2 operator failures is not valid, since the valves are interlocked. Since these are ISLOCA cutsets, and significant for both CDF and LERF, dependency will be significant. (This F&O originated from SR LE-C8)	This peer review finding has been resolved. The RHR-V-8 and RHR-V-9 have interlocks that prevent valve opening at normal RPV pressures above about 125 psig. Therefore human failure events RHRHUMN-V--8O3XX and RHRHUMN-V--9O3XX have been removed from the ISLOCA initiating event fault tree (that is, even if operators mistakenly select valve OPEN from the control board for either or both valves, the valves will not open).

F&O [Ref. 33]	2009 SR	Observations	Resolution [Ref. 43]
2-2	DA-C6	The number of plant-specific demands on standby components was mainly documented for the maintenance rule and MSPI components. Tier 3 PSA documents for PSA-2-DA-0002 show the details. Estimates based on the surveillance tests and maintenance acts as described in this SR should be performed even though the major components have been included in the MSPI data.	A sensitivity study was performed by replacing the baseline model failure data with data that was informed by the surveillance tests and maintenance acts as described in the associated SR. It was determined from this sensitivity that the finding has a negligible impact on quantitative results associated with the permanent extension of the ILRT interval. This sensitivity is presented in Section 5.4.3. Failure rate estimates for significant events not tracked in the MSPI data in the sensitivity are based on plant-specific surveillance test and maintenance records. Resolution of F&O 2-2 impacts the following component failure modes: C---W2 (compressor fails to start), C---W4 (compressor fails to run), FN--R3 (fan fails to start), FR--W4 (fan fails to run), AHUS---S3 (air handling unit fails to start), AHUR---W4 (air handling unit fails to run). The PRA model of record will be updated to use the revised data in the next PRA update.
2-14	SY-A4	Interviews with plant system engineers or operators have not been documented and cannot be verified by the peer review team. Original interviews were performed for the original IPE. System and operations change over time, and the system engineers and operators should be consulted with regard to the system models. (This F&O originated from SR SY-A4)	Finding 2-14 was resolved as part of the risk-informed technical specification initiative 5b license amendment request. System reviews with the system engineers were completed for all PRA systems with a focus on confirming that the PRA system analyses correctly reflect the as-built, as-operated plant, as well as to discuss recent operating history and any problems in system operation. The interviews and reviews were documented, and this documentation will be added to the system notebooks in the next PRA update. Discrepancies identified by the system engineer interviews had no impact on the PRA modeling and were documentation-related only, with the exception of two modeling conservatisms related to the reactor feedwater system model and the Standby Liquid Control (SLC) model. First, the feedwater system models only two paths for possible injection into the vessel when there are three possible paths. Second, the SLC system model contains a component failure event that, based on system design, may be overly conservative. These conservatisms do not have a significant impact on the PRA results. They will be examined as part of a future PRA update.

F&O [Ref. 33]	2009 SR	Observations	Resolution [Ref. 43]
2-16	SY-B13	Failure modes have been considered in development of the system models adequately. However, the exclusion of some failure modes was not adequately documented. Some failure modes could be important to system models. A sample review of the system models show that the following failure modes may not have been fully investigated: (d) failure of a closed component to remain closed especially for standby components where the failure would not be identified quickly - say months or greater). (f) failure of an open component to remain open (see above) (g) active component spurious operation (h) plugging of an active or passive component (i) leakage of an active or passive component (j) rupture of an active or passive component (k) internal leakage of a component (l) internal rupture of a component (m) failure to provide signal/operate (e.g., instrumentation) (n) spurious signal/operation For example, in the RHR system model, valves RHR-V54A/B could have a failure mode for fail to remain closed, which is not included in the model. The exposure time on these valves would rely on the surveillance tests. (This F&O originated from SR SY-A14)	This peer review finding was resolved. A Tier 3 calculation was prepared to ensure that failure modes have been considered in development of the system models adequately, with evaluation for both the inclusion and exclusion of the failure modes for components within the system boundary, including justification. Failure modes were added or corrected in the system models and system notebooks were updated based on this evaluation.

F&O [Ref. 33]	2009 SR	Observations	Resolution [Ref. 43]
2-17	SY-A14	The following requirements associated with system modeling are determined to be not adequate: (e) actual operational history (such as SOERs) indicating any past problems in the system operation [not documented], (l) the components and failure modes included in the model and justification for any exclusion of components and failure modes [also see F&O 2-16], (q) the sources of the above information (e.g., completed checklist from walkdowns, notes from discussions with plant personnel) [also see F&O 2-14]. The following should be enhanced: (f) system success criteria and relationship to accident sequence models (k) assumptions or simplifications made in development of the system models. The inadequate documentation limits the review of the completeness of the system models. (This F&O originated from SR SY-C2)	This peer review finding was resolved by enhancing system modeling documentation items associated with items (e), (l), (q), (f) and (k). (e) actual operational history (such as SOERs) indicating any past problems in the system operation was collected, and will be added to the system notebooks in a future PRA update, (f) documentation of system success criteria and relationship to accident sequence models was enhanced in the system notebooks, (k) documentation of assumptions or simplifications made in development of the system models was enhanced in the system notebooks, (l) the components and failure modes included in the model and justification for any exclusion of components and failure modes, and (q) the sources of the above information (e.g., notes from discussions with plant personnel) were documented. Note that for item (e), significant operating experience has been collected, but this information has not yet been incorporated into the system notebooks, and will be incorporated into the system notebooks during future PRA update.
2-18	LE-G6	The quantitative definition used for significant accident progression sequence was not documented. (This F&O originated from SR LE-G6)	This peer review finding was resolved. Section 6.3 of the Level 2 Notebook was enhanced to add the quantitative definition used for significant accident progression sequence.
2-28	IFPP-B3	Sources of model uncertainty and related assumptions for flood plant partitioning were not documented in the flooding notebooks. Neither do the Internal Flooding items included in PSA-2-QU-0001 Tables 5-2 and 5-3. Sources of model uncertainty and related assumptions for flood plant partitioning are not documented. (This F&O originated from SR IFPP-B3)	The PRA Quantification Notebook Table 5-3, documents uncertainties and related assumptions for the overall PRA, including uncertainties and related assumptions for flood plant partitioning. This information was added to the IF notebooks for completeness. Sensitivity studies, other than the standard set of sensitivities, i.e., CCFs set to 5th and 95th percentile and HEPs set to 5th and 95th percentile, are not directed for the base PRA model per the EPRI Uncertainties/Assumptions methodology, 1016737, and were not performed.

F&O [Ref. 33]	2009 SR	Observations	Resolution [Ref. 43]
3-1	DA-D1	The process of developing plant-specific parameter data updates based on plant-specific experience and generic data is described in PSA-2-DA-0002, Bayesian Update of CGS PSA Data. The process is focused on significant basic events. However, the process used to determine which events are significant and should be Bayesian updated appears to be faulted. A set of screening criteria based on risk achievement worth, F-V, and Birnbaum importance measures is applied, but the criteria for determination of significant (i.e., per PSA-2-DA-0002, "RAW value of 3 is typically used in risk ranking initiatives to identify risk important components.") differs from those applied in risk-informed applications (e.g., Maintenance Rule, where RAW of 2 and F-V of 0.005 are normally used). In the DA screening, a RAW of 3 is used as the criterion, so it is possible that some significant basic events could be screened from consideration using the process in PSA-2-DA-0002 (i.e., in Table 4 there would be a lower value for the CDF change for which a failure would be a candidate for Bayesian updating). Capability Category 2 for SR DA-D1 requires that realistic parameter estimates be calculated for all significant basic events. The process used to define which events are significant is not adequately objective and uses criteria that are inconsistent with selection criteria used for risk-informed applications (e.g. MR), and may result in underestimating the set of significant events. After discussion with CGS PRA personnel, they performed a sensitivity evaluation to estimate the impact of using more appropriate screening criteria. This exercise identified one additional component type (RV/SV) for which there were no EPIX failures. (This F&O originated from SR DA-D1)	This peer review finding has been resolved. Screening criteria consistent with important plant applications of the base PRA are now used, per RG 1.200, Rev. 2 (footnote page 10: Significant basic event/contributor: The basic events (i.e., equipment unavailabilities and human failure events) that have a Fussell-Vesely (FV)importance greater than 0.005 or a risk-achievement worth greater than 2): - The identification of plant-specific parameter data updates now uses a risk-achievement worth (RAW) value greater than 2 as one screening criterion, and - A FV of greater than 5E-3 is typically used in risk ranking initiatives to identify risk-significant components. The identification of plant-specific parameter data updates now uses a FV of 1E-4, because it was practical to do so.

F&O [Ref. 33]	2009 SR	Observations	Resolution [Ref. 43]
3-11	DA-C15	The accident sequence model includes top event EAC, recovery of onsite AC power. The text of the AS notebook refers to Appendix D of that notebook for the onsite power recovery calculation. Appendix D is a portion of ERIN letter C1069805-3919 "Completion of CGS PSA Model Modifications to Address PSA Certification Comments (P.O.00303454)", August 3, 1999, titled Emergency AC Power Recovery. That analysis uses as its basis a 1993 regulatory analysis, SECY-93-190. There are 2 issues with this. First, the basis for the onsite AC power recovery is a set of EDG repair data from before 1993, i.e., significantly more than 16 years old, and originally based on relatively few data points. Second, this represents credit for repair of failed equipment without checking against plant-specific experience. Credit should not be taken for repair of failed equipment, particularly EDGs, without sound plant-specific basis. Significance may be increased if tied to the F&O on consequential LOOP. (This F&O originated from SR SY-A24)	This peer review finding was resolved by enhancing Appendix D of the accident sequence notebook to further support that the existing EDG non-recovery values based on SECY-93-190 are judged to be appropriate for CGS. Further, the Emergency AC Power recovery values from SECY-93-190 used in the CGS PRA were compared with more recent data from NUREG/CR-6890. The SECY-93-190 data produces non-recovery probabilities that are higher relative to the NUREG/CR-6890 data. The following comparison is made: Recovery Time (hr),SECY-93-190,NUREG/CR-6890 0.5, 0.89, 0.86 2, 0.86, 0.65 3, 0.78, 0.56 4, 0.71, 0.48 6, 0.59, 0.37 10, 0.4, 0.24 15, 0.29, 0.14 24, 0.23, 0.24 The SECY-93-190 data provides higher non-recovery values for the entire range of EDG recovery times. Although the NUREG/CR-6890 diesel non-recovery data development is more recent, there is one prominent concern about the NUREG/CR-6890 data for purposes of the Columbia PSA modeling. The NUREG/CR-6890 non-recovery values assume that the diesel generator that is easiest to repair will be chosen for recovery. What is not clear from the NUREG/CR-6890 treatment is how the SPAR models address the possibility that the DG that is easiest to repair actually won't be restored because the associated SW pump or RHR pump is out of service. The Columbia model assumes 50 percent likelihood for recovery of DG-1 or DG-2, unless the SW or RHR pump on one of the diesel generators is out of service. Due to this potential conflict, the NUREG-6890 data was not used. The SECY-93-190 data is judged to be the most applicable and realistic.
4-7	MU-C1	While consideration of pending model changes has occurred for important applications (e.g. DGAOT), there was no identified Columbia process that requires that pending changes be considered for applications. Having such a process is an explicit requirement of the standard. (This F&O originated from SR MU-C1)	The peer review finding was resolved. A new Section 4.4 was added to the model maintenance and update procedure, SYS-4-34, that documents the Columbia process that requires pending model changes to be considered for applications. Also, a list of current applications that require a consideration of pending model changes in applications was added in SYS-4-34, Attachment 8.2.

F&O [Ref. 33]	2009 SR	Observations	Resolution [Ref. 43]
6-10	SY-B1	A variety of common cause basic events exist in the model without documentation provided to substantiate their basis. For example, Table 1 of PSA-2-DA-0004 lists 13 CCF events with probabilities of zero related to relays, vacuum breakers, and nitrogen bottles. Table 1 also lists two events that are termed CCF place keepers but not true CCF events. These are not further discussed. Table 1 lists CCF events with apparently generic values (1E-6), but no discussion or justification is provided to substantiate the value. Table 1 lists CCF events for 5 of 7 ADS valves and 5 of 11 SRVs, with values of 1.24E-6, but no discussion / justification is provided. Table 2 lists an event (CRDSV--24567C8LL) for "8 of 8", but uses the NRC data for "2 of 2" instead of the closer "6 of 6" value. Upon review, CGS noted that this event is not needed in the model and will be removed in the next update. (This F&O originated from SR SY-B1)	This peer review finding has been resolved. The documentation of CCF events has been refined and improved. The bases for all CCF values are provided, based on the CCF analysis process.
6-8	SY-B1	Several issues were identified in the review of CCF: 1) The process to develop common cause groups is not documented in the CCF NB and therefore justification is not provided for the grouping scheme. Per CGS, selection of CCF groups was performed following the guidance of NUREG/CR-5485 based on similarities in service conditions, environment, design or manufacturer, and maintenance. NUREG/CR-5485 is not currently referenced in PSA-2-DA-0004. 2) There are limited formulae documented in the CCF data package PSA-2-DA-0004. As a result, the bases for the calculations embedded in the spreadsheets are not fully documented. Discussions with CGS staff indicate the Alpha CCF calculations were performed incorrectly. Moreover, based on the formulae in NUREG/CR-5485, the CCF basic event probabilities may be slightly more conservative. 3) As a result of the above, CCF basic events are incorrectly calculated. (This F&O originated from SR SY-B1 and B3)	This peer review finding has been resolved. The process to develop common cause groups is now documented in PSA-2-DA-004. CGS employs staggered testing of redundant trains modeled in the PRA. Therefore, CCF probabilities were recalculated using the CCF equations for staggered testing, and these equations are documented in PSA-2-DA-004, and the PRA was updated accordingly.
6-9	SY-B1	Per Section 2 of PSA-2-DA-0004, the common cause calculations are based on a non-staggered testing scheme based on the prior use of this scheme for the original PRA and the fact that current CGS test intervals / test information has not been developed for the current data update. PSA-2-DA-0004 notes that the non-staggered approach is conservative. The staggered approach should be utilized where appropriate to reflect plant practices.	This peer review finding has been resolved. CGS employs staggered testing of redundant trains modeled in the PRA. Therefore, CCF probabilities were recalculated using the CCF equations for staggered testing, and these equations are documented in PSA-2-DA-004, and the PRA was updated.

B. Appendix B – Detailed Development of Corrosion Sensitivity Studies

The tables below provide the underlying detail associated with the additional sensitivities shown in Table 5-10. The calculations to produce these tables are performed in a manner described in Section 5.4.1 and Reference 26.

Table B-1 – Liner Corrosion Sensitivities (Base Case – Case 1)

Step	Description	Containment (Excluding Basemat)	Containment Basemat
1	Historical Steel Liner Flaw Likelihood / Failure Data	5.19E-03	1.30E-03
2	Age-Adjusted Steel Liner Flaw Likelihood (Year 1)	2.05E-03	5.13E-04
	Age-Adjusted Steel Liner Flaw Likelihood (Avg Years 5-10)	5.19E-03	1.30E-03
	Age-Adjusted Steel Liner Flaw Likelihood (Year 15)	1.43E-02	3.59E-03
	Age-Adjusted Steel Liner Flaw Likelihood (Avg 15 Years)	6.45E-03	1.61E-03
3	Flaw Likelihood (3 Years)	0.71%	0.18%
	Flaw Likelihood (10 Years)	4.14%	1.04%
	Flaw Likelihood (15 Years)	9.68%	2.42%
4	Likelihood of Breach in Containment Given Steel Liner Flaw	1.00%	0.10%
5	Visual Inspection Detection Failure Likelihood	10.00%	100.00%
6	Likelihood of Non-Detected Containment Leakage (3 yr)	7.12E-06	1.78E-06
	Likelihood of Non-Detected Containment Leakage (10 yr)	4.14E-05	1.04E-05
	Likelihood of Non-Detected Containment Leakage (15 yr)	9.68E-05	2.42E-05

Table B-2 – Liner Corrosion Sensitivities (Case 2 – Doubles Every 2 Years)

Step	Description	Containment (Excluding Basemat)	Containment Basemat
1	Historical Steel Liner Flaw Likelihood / Failure Data	5.19E-03	1.30E-03
2	Age-Adjusted Steel Liner Flaw Likelihood (Year 1)	4.62E-04	1.15E-04
	Age-Adjusted Steel Liner Flaw Likelihood (Avg Years 5-10)	5.19E-03	1.30E-03
	Age-Adjusted Steel Liner Flaw Likelihood (Year 15)	5.91E-02	1.48E-02
	Age-Adjusted Steel Liner Flaw Likelihood (Avg 15 Years)	1.34E-02	3.34E-03
3	Flaw Likelihood (3 Years)	0.20%	0.05%
	Flaw Likelihood (10 Years)	3.46%	0.86%
	Flaw Likelihood (15 Years)	20.07%	5.02%
4	Likelihood of Breach in Containment Given Steel Liner Flaw	1.00%	0.10%
5	Visual Inspection Detection Failure Likelihood	10.00%	100.00%
6	Likelihood of Non-Detected Containment Leakage (3 yr)	2.04E-06	5.10E-07
	Likelihood of Non-Detected Containment Leakage (10 yr)	3.46E-05	8.64E-06
	Likelihood of Non-Detected Containment Leakage (15 yr)	2.01E-04	5.02E-05

Table B-3 – Liner Corrosion Sensitivities (Doubles Every 10 Years)

Step	Description	Containment (Excluding Basemat)	Containment Basemat
1	Historical Steel Liner Flaw Likelihood / Failure Data	5.19E-03	1.30E-03
2	Age-Adjusted Steel Liner Flaw Likelihood (Year 1)	3.29E-03	8.21E-04
	Age-Adjusted Steel Liner Flaw Likelihood (Avg Years 5-10)	5.19E-03	1.30E-03
	Age-Adjusted Steel Liner Flaw Likelihood (Year 15)	8.70E-03	2.17E-03
	Age-Adjusted Steel Liner Flaw Likelihood (Avg 15 Years)	5.59E-03	1.40E-03
3	Flaw Likelihood (3 Years)	1.06%	0.26%
	Flaw Likelihood (10 Years)	4.58%	1.15%
	Flaw Likelihood (15 Years)	8.38%	2.10%
4	Likelihood of Breach in Containment Given Steel Liner Flaw	1.00%	0.10%
5	Visual Inspection Detection Failure Likelihood	10.00%	100.00%
6	Likelihood of Non-Detected Containment Leakage (3 yr)	1.06E-05	2.65E-06
	Likelihood of Non-Detected Containment Leakage (10 yr)	4.58E-05	1.15E-05
	Likelihood of Non-Detected Containment Leakage (15 yr)	8.38E-05	2.10E-05

Table B-4 – Liner Corrosion Sensitivities (Case 4 – 15% Detection)

Step	Description	Containment (Excluding Basemat)	Containment Basemat
1	Historical Steel Liner Flaw Likelihood / Failure Data	5.19E-03	1.30E-03
2	Age-Adjusted Steel Liner Flaw Likelihood (Year 1)	2.05E-03	5.13E-04
	Age-Adjusted Steel Liner Flaw Likelihood (Avg Years 5-10)	5.19E-03	1.30E-03
	Age-Adjusted Steel Liner Flaw Likelihood (Year 15)	1.43E-02	3.59E-03
	Age-Adjusted Steel Liner Flaw Likelihood (Avg 15 Years)	6.45E-03	1.61E-03
3	Flaw Likelihood (3 Years)	0.71%	0.18%
	Flaw Likelihood (10 Years)	4.14%	1.04%
	Flaw Likelihood (15 Years)	9.68%	2.42%
4	Likelihood of Breach in Containment Given Steel Liner Flaw	1.00%	0.10%
5	Visual Inspection Detection Failure Likelihood	15.00%	100.00%
6	Likelihood of Non-Detected Containment Leakage (3 yr)	1.07E-05	1.78E-06
	Likelihood of Non-Detected Containment Leakage (10 yr)	6.22E-05	1.04E-05
	Likelihood of Non-Detected Containment Leakage (15 yr)	1.45E-04	2.42E-05

Table B-5 – Liner Corrosion Sensitivities (Case 5 – 5% Detection)

Step	Description	Containment (Excluding Basemat)	Containment Basemat
1	Historical Steel Liner Flaw Likelihood / Failure Data	5.19E-03	1.30E-03
2	Age-Adjusted Steel Liner Flaw Likelihood (Year 1)	2.05E-03	5.13E-04
	Age-Adjusted Steel Liner Flaw Likelihood (Avg Years 5-10)	5.19E-03	1.30E-03
	Age-Adjusted Steel Liner Flaw Likelihood (Year 15)	1.43E-02	3.59E-03
	Age-Adjusted Steel Liner Flaw Likelihood (Avg 15 Years)	6.45E-03	1.61E-03
3	Flaw Likelihood (3 Years)	0.71%	0.18%
	Flaw Likelihood (10 Years)	4.14%	1.04%
	Flaw Likelihood (15 Years)	9.68%	2.42%
4	Likelihood of Breach in Containment Given Steel Liner Flaw	1.00%	0.10%
5	Visual Inspection Detection Failure Likelihood	5.00%	100.00%
6	Likelihood of Non-Detected Containment Leakage (3 yr)	3.56E-06	1.78E-06
	Likelihood of Non-Detected Containment Leakage (10 yr)	2.07E-05	1.04E-05
	Likelihood of Non-Detected Containment Leakage (15 yr)	4.84E-05	2.42E-05

Table B-6 – Liner Corrosion Sensitivities (Case 6 – Breach / 10% Cylinder / 1% Basement)

Step	Description	Containment (Excluding Basemat)	Containment Basemat
1	Historical Steel Liner Flaw Likelihood / Failure Data	5.19E-03	1.30E-03
2	Age-Adjusted Steel Liner Flaw Likelihood (Year 1)	2.05E-03	5.13E-04
	Age-Adjusted Steel Liner Flaw Likelihood (Avg Years 5-10)	5.19E-03	1.30E-03
	Age-Adjusted Steel Liner Flaw Likelihood (Year 15)	1.43E-02	3.59E-03
	Age-Adjusted Steel Liner Flaw Likelihood (Avg 15 Years)	6.45E-03	1.61E-03
3	Flaw Likelihood (3 Years)	0.71%	0.18%
	Flaw Likelihood (10 Years)	4.14%	1.04%
	Flaw Likelihood (15 Years)	9.68%	2.42%
4	Likelihood of Breach in Containment Given Steel Liner Flaw	10.00%	1.00%
5	Visual Inspection Detection Failure Likelihood	10.00%	100.00%
6	Likelihood of Non-Detected Containment Leakage (3 yr)	7.12E-05	1.78E-05
	Likelihood of Non-Detected Containment Leakage (10 yr)	4.14E-04	1.04E-04
	Likelihood of Non-Detected Containment Leakage (15 yr)	9.68E-04	2.42E-04

Table B-7 – Liner Corrosion Sensitivities (Case 7 - Breach / 0.1% Cyl / 0.01% Basement)

Step	Description	Containment (Excluding Basemat)	Containment Basemat
1	Historical Steel Liner Flaw Likelihood / Failure Data	5.19E-03	1.30E-03
2	Age-Adjusted Steel Liner Flaw Likelihood (Year 1)	2.05E-03	5.13E-04
	Age-Adjusted Steel Liner Flaw Likelihood (Avg Years 5-10)	5.19E-03	1.30E-03
	Age-Adjusted Steel Liner Flaw Likelihood (Year 15)	1.43E-02	3.59E-03
	Age-Adjusted Steel Liner Flaw Likelihood (Avg 15 Years)	6.45E-03	1.61E-03
3	Flaw Likelihood (3 Years)	0.71%	0.18%
	Flaw Likelihood (10 Years)	4.14%	1.04%
	Flaw Likelihood (15 Years)	9.68%	2.42%
4	Likelihood of Breach in Containment Given Steel Liner Flaw	0.10%	0.01%
5	Visual Inspection Detection Failure Likelihood	10.00%	100.00%
6	Likelihood of Non-Detected Containment Leakage (3 yr)	7.12E-07	1.78E-07
	Likelihood of Non-Detected Containment Leakage (10 yr)	4.14E-06	1.04E-06
	Likelihood of Non-Detected Containment Leakage (15 yr)	9.68E-06	2.42E-06

Table B-8 – Liner Corrosion Sensitivities (Case 8 – Lower Bound)

Step	Description	Containment (Excluding Basemat)	Containment Basemat
1	Historical Steel Liner Flaw Likelihood / Failure Data	5.19E-03	1.30E-03
2	Age-Adjusted Steel Liner Flaw Likelihood (Year 1)	3.29E-03	8.21E-04
	Age-Adjusted Steel Liner Flaw Likelihood (Avg Years 5-10)	5.19E-03	1.30E-03
	Age-Adjusted Steel Liner Flaw Likelihood (Year 15)	8.70E-03	2.17E-03
	Age-Adjusted Steel Liner Flaw Likelihood (Avg 15 Years)	5.59E-03	1.40E-03
3	Flaw Likelihood (3 Years)	1.06%	0.26%
	Flaw Likelihood (10 Years)	4.58%	1.15%
	Flaw Likelihood (15 Years)	8.38%	2.10%
4	Likelihood of Breach in Containment Given Steel Liner Flaw	0.10%	0.01%
5	Visual Inspection Detection Failure Likelihood	5.00%	100.00%
6	Likelihood of Non-Detected Containment Leakage (3 yr)	5.29E-07	2.65E-07
	Likelihood of Non-Detected Containment Leakage (10 yr)	2.29E-06	1.15E-06
	Likelihood of Non-Detected Containment Leakage (15 yr)	4.19E-06	2.10E-06

Table B-9 – Liner Corrosion Sensitivities (Case 9 - Upper Bound)

Step	Description	Containment (Excluding Basemat)	Containment Basemat
1	Historical Steel Liner Flaw Likelihood / Failure Data	5.19E-03	1.30E-03
2	Age-Adjusted Steel Liner Flaw Likelihood (Year 1)	4.62E-04	1.15E-04
	Age-Adjusted Steel Liner Flaw Likelihood (Avg Years 5-10)	5.19E-03	1.30E-03
	Age-Adjusted Steel Liner Flaw Likelihood (Year 15)	5.91E-02	1.48E-02
	Age-Adjusted Steel Liner Flaw Likelihood (Avg 15 Years)	1.34E-02	3.34E-03
3	Flaw Likelihood (3 Years)	0.20%	0.05%
	Flaw Likelihood (10 Years)	3.46%	0.86%
	Flaw Likelihood (15 Years)	20.07%	5.02%
4	Likelihood of Breach in Containment Given Steel Liner Flaw	10.00%	1.00%
5	Visual Inspection Detection Failure Likelihood	15.00%	100.00%
6	Likelihood of Non-Detected Containment Leakage (3 yr)	3.06E-05	5.10E-06
	Likelihood of Non-Detected Containment Leakage (10 yr)	5.18E-04	8.64E-05
	Likelihood of Non-Detected Containment Leakage (15 yr)	3.01E-03	5.02E-04