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

Hope Creek Generating Station
Renewed Facility Operating License No. NPF-57
NRC Docket No. 50-354

Subject: **License Amendment Request to Amend Technical Specifications (TS) 6.8.4.f for Permanent Extension of Type A and Type C Leak Rate Test Frequencies**

In accordance with the provisions of 10 CFR 50.90, PSEG Nuclear LLC (PSEG) is submitting a request for an amendment to the Technical Specifications (TS) for Hope Creek Generating Station (Hope Creek).

The proposed amendment would modify TS requirements by replacing the reference to Regulatory Guide (RG) 1.163 with a reference to Nuclear Energy Institute (NEI) Topical Report 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.

Attachment 1 provides an evaluation of the proposed change. Attachment 2 provides the existing TS pages marked up to show the proposed changes. Attachment 3 provides a Risk Assessment for the Type A Permanent Extension Request.

PSEG requests approval of this LAR in accordance with standard NRC approval process and schedule. Once approved, the amendment will be implemented within 60 days from the date of issuance.

In accordance with 10 CFR 50.91, a copy of this application, with attachments, is being provided to the designated State of New Jersey Official.

There are no regulatory commitments contained in this letter.

If you have any questions or require additional information, please contact Ms. Tanya Timberman at 856-339-1426.

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

Executed on 10/6/16
(Date)

Respectfully,

Eric S. Carr
Site Vice President
Hope Creek Generating Station

Attachments:
1. Evaluation of the Proposed Change
2. Proposed Technical Specification Chnages (Mark-up)
3. Risk Assessment for the Type A Permanent Extension Request

cc: Mr. D. Dorman, Administrator, Region I, NRC
Ms. C. Parker, Project Manager, NRC
NRC Senior Resident Inspector, Hope Creek
Mr. P. Mulligan, Chief, NJBNE
PSEG Corporate Commitment Tracking Coordinator
Hope Creek Commitment Tracking Coordinator

Attachment 1

Evaluation of the Proposed Change

EVALUATION OF THE PROPOSED CHANGE

License Amendment Request to Revise Technical Specifications (TS) 6.8.4.f for Permanent Extension of Type A and Type C Leak Rate Test Frequencies

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EVALUATION OF THE PROPOSED CHANGE

1.0 SUMMARY DESCRIPTION

This evaluation supports a request to amend Renewed Facility Operating License NPF-57 for Hope Creek Generating Station (HCGS). The proposed change would revise the Operating License by amending Technical Specifications (TS) Section 6.8.4.f, "Primary Containment Leakage Rate Testing Program." The proposed changes to the Technical Specifications contained herein would revise HCGS TS 6.8.4.f, by replacing the reference to Regulatory Guide (RG) 1.163 (Reference 1) with a reference to Nuclear Energy Institute (NEI) Topical Report NEI 94-01, Revision 3-A, dated July 2012 (Reference 2) and the conditions and limitations specified in NEI 94-01, Revision 2-A, dated October 2008 (Reference 8), as the implementation documents used by HCGS to implement the performance-based leakage testing program in accordance with Option B of 10 CFR Part 50, Appendix J. The proposed change would also delete the listing of a one-time exception previously granted to Integrated Leak Rate Test (ILRT) test frequency.

2.0 DETAILED DESCRIPTION

HCGS TS 6.8.4.f, "Primary Containment Leakage Rate Testing Program," currently states, in part:

> A program shall be established, implemented, and maintained to comply with 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 exception:
>
> a. NEI 94-01-1995, Section 9.2.3: The first Type A test performed after April 12, 1994 shall be performed no later than April 12, 2009.

The proposed changes to HCGS TS 6.8.4.f will replace the reference to RG 1.163 with a reference to NEI Topical Report NEI 94-01 Revisions 2-A and 3-A.

Additionally, this LAR incorporates an administrative change to TS 6.8.4.f to delete exception a. regarding the performance of the next HCGS Type A test to be performed no later than April 12, 2009. This Type A test information is no longer applicable since the test date occurred in the past. Therefore, exception a. will be deleted in its entirety.

The proposed change will revise TS 6.8.4.f to state, in part:

> A program shall be established, implemented, and maintained to comply with 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 limitations and conditions specified in NEI 94-01, Revision 2-A, dated October 2008.

Markup of TS 6.8.4.f is provided in Attachment 2.

A plant specific risk assessment conducted to support this proposed change, as summarized in Section 3.5 of this attachment, is presented in Attachment 3 of this LAR. This risk assessment follows the guidelines of US Nuclear Regulatory Commission (NRC) RG 1.174, Revision 2 (Reference 3) and NRC RG 1.200, Revision 2 (Reference 4). The risk assessment concluded that increasing the ILRT test frequency 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 HCGS risk profiles.

3.0 TECHNICAL EVALUATION

3.1 Description of Primary Containment System

The HCGS General Electric Mark I primary containment system is designed to condense the steam released during a postulated loss-of-coolant accident (LOCA), to limit the release of fission products associated with such an accident, and to serve as a source of water for the emergency core cooling system (ECCS).

The steel containment is an American Society of Mechanical Engineers (ASME) Boiler & Pressure Vessel (B&PV) Code Class MC vessel designed to house the Nuclear Steam Supply System (NSSS).

The primary containment consists of a drywell, a pressure suppression chamber, and an interconnecting vent system. The drywell is a steel pressure vessel with the shape of a light bulb. The pressure suppression chamber is a torus shaped steel pressure vessel located below and encircling the drywell.

3.1.1 Drywell

The drywell is a steel pressure vessel with a spherical lower portion 68 feet inside diameter, a cylindrical upper portion 40 feet 6 inches inside diameter, and a removable, flanged, hemi-ellipsoidal top head, 33 feet 2 inches inside diameter. Its overall height is 114 feet 9 inches. The bottom elevation of the spherical portion is 77 feet 10 inches. Inner and outer steel cylindrical skirts that are encased in concrete and anchored to a concrete pedestal support the drywell. The outer skirt is designed to transfer the drywell loads at the bottom of the drywell into the foundation and is the primary support for the drywell during construction. The inner skirt extends into the drywell and transfers reactor pressure vessel (RPV) loads into the foundation. The inside of the drywell is filled with concrete up to Elevation 86 feet 11 inches. The drywell is enclosed by the concrete drywell shield wall. An air gap of nominally 2 inches separates the drywell vessel from the concrete drywell shield wall. The air gap permits displacement of the vessel, but the size of the gap is limited to allow transfer of postulated jet impingement forces into the drywell shield wall without rupturing the vessel.

There are a few, very localized areas, below Elevation 100 feet 0 inches, where the air gap is reduced to as narrow as 0.5 inches. Generally, the reduced gap permits unrestrained displacement of the drywell vessel. Where restraint occurs, the structural effects have been included in the shell analysis. Additionally, a few localized areas exist where no concrete backing is provided. These areas have been evaluated to verify that the vessel alone can satisfactorily resist postulated jet impingement forces without the added resistance of the shield wall.

The drywell is supported laterally by the drywell shield wall near the top of the cylindrical portion of the vessel. The lateral supports are designed to permit vertical and radial displacement of the vessel.

Beam supports are provided for the drywell structural steel framing at Elevations 100 feet 2 inches and 121 feet 7-1/2 inches. The supports are designed to permit differential radial movement between the beams and the shell.

Weld pads are provided on the drywell shell for the attachment of pipe supports, pipe restraints, and similar items.

Containment spray headers at Elevations 129 feet 2 inches and 137 feet 3 inches, and a monorail at Elevation 135 feet 6 inches, are supported by the drywell shell.

The drywell water seal plate is supported by the drywell at elevation 176 feet 11 inches.

Access to the drywell is provided through a bolted equipment hatch at Elevation 107 feet and another bolted equipment hatch with a double-door air lock at Elevation 107 feet.

3.1.2 Drywell Head Assembly

The drywell head provides a flanged removable closure at the top of the drywell for RPV access during refueling operations. The drywell head assembly consists of a hemi-ellipsoidal head held in place to the drywell flange by bolts. The head is made of 1-1/2-inch thick plate with a 4-inch thick flange and is secured with 180, 2-1/2-inch diameter bolts to the 4-inch thick drywell flange. The head to drywell flanged connection is made leak tight by two replaceable compression seals. Test connections are provided between the seals to allow pneumatic testing from a remote location, outside the steel containment. A personnel access manhole with double, testable seals, is provided in the drywell head.

3.1.3 Drywell Equipment Hatches and Personnel Air Lock

Two 12-foot inside diameter equipment hatches in the drywell, at elevation 107 feet, permit the transfer of equipment and components. One hatch, at azimuth 135^o, consists of a hatch barrel and a bolted cover with double, testable seals. The other hatch, at azimuth 315^o, with similar seals, is furnished with a personnel air lock welded to the removable cover. The personnel air lock is an 8-foot 10-1/2-inch inside diameter cylindrical pressure vessel with inner and outer bulkheads. Interlocked doors, 3-feet 9-inches wide by 7-feet 1-inch high, with double, testable

compression seals are furnished in each bulkhead. The doors are mechanically interlocked to ensure that at least one door is locked to maintain the primary containment integrity.

3.1.4 Control Rod Drive Removal Hatch

One 3-foot inside diameter control rod drive (CRD) removal hatch at Elevation 103 feet 6 inches in the drywell permits transfer of the CRD assemblies. The hatch is furnished with double, testable seals and a bolted cover.

3.1.5 Drywell Penetrations

Two general types of process pipe penetrations are provided: those that must accommodate thermal movement, type A, and those that experience insignificant thermal stress, types B and C.

Type A penetrations consist of a penetration nozzle welded to the drywell shell, a triple flued head with primary and secondary bellows located outside the drywell, an inner guard pipe and the process pipe.

The bellows used in Type A triple flued head containment penetrations are designed, fabricated, tested, and examined in accordance with the requirements for Class 2 components of ASME B&PV Section III Code.

Type B penetrations consist of a penetration nozzle welded to the drywell shell, a double flued head located outside the drywell, and the process pipe.

Type C penetrations consist of a process pipe welded to the drywell shell.

3.1.6 Suppression Chamber

The suppression chamber consists of 16 mitered cylindrical shell segments joined together to form a torus shaped pressure vessel located below and encircling the drywell. The suppression chamber has a major diameter of 112 feet 8 inches, a minor or chamber diameter of 30 feet 8 inches, and contains water to an approximate depth of 14 feet.

The 1-inch thick suppression chamber shell is reinforced by full 360^{o} ring beams located 3-1/2 inches from each mitered joint and by partial ring beams at each midcylinder location, which extend a short distance beyond the suppression chamber equator. The ring beams provide stiffening for the suppression chamber shell and also allow for transfer of shell pressure loads and support reactions from the vent system, piping, spray header, and monorail and catwalk to the suppression chamber support columns.

The suppression chamber is supported on columns symmetrically arranged in two concentric rings. These columns consist of 2-1/4-inch thick flange plates connected by a 1-inch thick web. The columns are pinned to the base plate assembly at the bottom and to the column connection assembly at the top, thus carrying only axial loads. Horizontal loads on the suppression chamber are transferred into the drywell foundation pedestal by a horizontal restraint system.

The horizontal restraint has pinned connections and slotted holes to allow for thermal expansion of the suppression chamber.

3.1.7 Suppression Chamber Access Hatches

Four 4-foot inside diameter access hatches in the suppression chamber permit personnel access and the transfer of equipment and components. Each hatch is furnished with double, testable seals.

3.1.8 Vent System

The drywell and the suppression chamber are connected by eight equally spaced vent pipes, each with an internal diameter of 6 feet 2 inches. These vent pipes are connected to a common mitered header within the suppression chamber with a major diameter of 112 feet 8 inches and a minor diameter of 4 feet 3 inches.

Connected to the header are 80 downcomers that terminate at Elevation 68 feet 0-1/2 inch, below the normal water level of the suppression pool at Elevation 71 feet 2-1/2 inches. The downcomers have a 2-foot nominal diameter. At the drywell end, the vent line openings are protected by jet deflectors to prevent damage to the vent system from postulated jet impingement loadings originating in the drywell. A vacuum breaker assembly is located at the suppression chamber end of each vent line to limit differential pressure between the drywell and suppression chamber. The vent lines are provided with two-ply testable expansion bellows assemblies at the suppression chamber penetrations to accommodate differential movement between the drywell and suppression chamber.

The vent system is supported in the suppression chamber by columns, an upper truss, and a downcomer bracing system. The columns transfer vent system loads into the suppression chamber ring girders. The upper truss connects the vent line and vent header to the ring girder above.

3.2 Modifications to Primary Containment

Under the Fukushima project, several design change packages (DCPs) impacted HCGS. These are listed below:

80110321 - FLEX Mechanical Connections
80110322 - FLEX Electrical Modifications and Connections
80112012 - FLEX Specific Mechanical Modifications
80113941 - Hardened Containment Vent Mechanical
80113942 - Hardened Containment Vent Electrical
80115583 - Containment Hardened Vent Extension

None of the above DCPs impact the containment liner.

DCPs 80113941 and 80115583 impact the containment isolation valves as follows:

Install a redundant backup nitrogen system (cylinders, tubing and associated structural supports) to provide motive air/gas to actuate hardened containment vent system (HCVS) air operated valves (AOVs) for a minimum of eight (8) cycles within the first 24 hours after a beyond-design-basis external event (BDBEE).

Install a compressed gas purge system (cylinders, tubing, and associated structural supports) to purge the HCVS piping with argon, after venting, to prevent oxygen from entering the piping. The purge system is designed for a minimum of eight (8) purges to correspond to eight (8) cycles of HCVS AOV operation within the first 24 hours after a BDBEE.

Analyses performed at other sites implementing HCVS, have indicated that the dynamic load on the piping system, associated with rapid opening of HCVS valves is exceedingly large, and most plants which are acquiring new HCVS valves are specifying opening times of 30 to 60 seconds. Therefore, actuator H1GS-GS-HV-11541 is modified by the installation of a needle valve / flow control valve on tubing between solenoid valve outlet port and the actuator air pilot valve in order to slow down the opening stroke time of the Torus Vent Isolation Valve to greater than 30 seconds.

Analyses have shown that slowing down the stroke time to 20 seconds results in acceptable dynamic forces.

None of the work involved in DCPs 80113941 and 80115583 impacts the scope of the Primary Containment Leakage Rate Testing Program.

3.3 Emergency Core Cooling System Net Positive Suction Head Analysis

The suction piping for all pumps required for safe shutdown of the reactor, during both normal and accident conditions, including the cooling of both the core and the containment, is designed and located to ensure adequate net positive suction head (NPSH). The available NPSH for the residual heat removal (RHR) and core spray pumps is based on a torus water temperature of 212^{o}F, with the pool surface at 14.7 psia. The calculated available NPSH for the high pressure coolant injection (HPCI) pump is based on a water temperature of 170^{o}F, with the pool surface at 14.7 psia.

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. 10 CFR 50, Appendix J also ensures that periodic surveillances of reactor containment penetrations and isolation valves are performed so that proper maintenance and repairs are made during the service life of the containment and of the systems and components penetrating primary containment. The limitation on containment leakage provides assurance that the containment would perform its design function following an accident up to and including the plant DBA. Appendix J identifies

three types of required tests: 1) Type A tests, intended to measure the primary containment overall integrated leakage rate; 2) Type B tests, intended to detect local leaks and to measure leakage across pressure-containing or leakage limiting boundaries (other than valves) for primary containment penetrations, and; 3) Type C tests, intended to measure 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 5) with certain modifications and additions. Option B, in concert with RG 1.163 and NEI 94-01, Revision 0, allows licensees with a satisfactory ILRT performance history (i.e., two consecutive, successful Type A tests) to reduce the test frequency for the containment Type A (ILRT) test from three tests in 10 years to one test in 10 years. This relaxation was based on an NRC risk assessment contained in NUREG-1493, (Reference 6) and Electric Power Research Institute (EPRI) TR-104285 (Reference 7) both of which showed that the risk increase associated with extending the ILRT surveillance interval was very small. In addition to the 10-year ILRT interval, provisions for extending the test interval an additional 15 months were considered in the establishment of the intervals allowed by RG 1.163 and NEI 94-01, Revision 2-A, but this extension of interval "should be used only in cases where refueling schedules have been changed to accommodate other factors."

In 2008, NEI 94-01, Revision 2-A (Reference 8), was issued. This document describes an acceptable approach for implementing the optional performance-based requirements of Option B to 10 CFR 50, Appendix J, subject to the limitations and conditions noted in Section 4.0 of the NRC 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 by RG 1.163 and NRC SERs of June 25, 2008 (Reference 9), and June 8, 2012 (Reference 10), as an acceptable methodology for complying with the provisions of Option B in 10 CFR 50, Appendix J. The regulatory positions stated in RG 1.163 as modified by References 9 and 10 are incorporated in this document. It delineates a performance-based approach for determining Type A, Type B, and Type C containment

leakage rate surveillance testing frequencies. Justification for extending test intervals is based on the performance history and risk insights. Extensions of 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 which 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, states, in part, 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 MSIVs) or to valves held to the base interval (30 months) due to unsatisfactory LLRT performance*.

3.4.2 Current HCGS ILRT Requirements

On September 18, 1997, the NRC approved Amendment No. 104 for HCGS authorizing the implementation of 10 CFR 50, Appendix J, Option B for Types A, B and C tests (Reference 13).

Option B states that specific existing exemptions to Option A are still applicable unless specifically revoked by the NRC. Exemptions from certain requirements of Appendix J to 10 CFR Part 50, are identified in HCGS License Condition 2.D. These exemptions are unaffected by this LAR.

Currently, TS 6.8.4.f requires that a program be established to comply with the containment leakage rate testing requirements of 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. The program is required to be in accordance with the guidelines contained in RG 1.163 (Reference 1). RG 1.163 endorses, with certain exceptions, NEI 94-01, Revision 0, (Reference 5) as an acceptable method for complying with the provisions of Appendix J, Option B.

RG 1.163, Section C.1 states that licensees intending to comply with 10 CFR 50, Appendix J, Option B, should establish test intervals based upon the criteria in Section 11.0 of NEI 94-01 (Reference 5) rather than using test intervals specified in ANSI/ANS 56.8-1994. NEI 94-01 Revision 0, 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 1.0 La (where La 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, Revision 0 is based, in part, upon a generic evaluation documented in NUREG-1493 (Reference 6). The evaluation documented in NUREG-1493 included a study of the dependence of reactor accident risks on containment leak tightness for differing containment types. NUREG-1493 concluded in Section 10.1.2 that reducing the frequency of Type A tests (ILRT) from the original three (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 concluded that increasing the interval between ILRTs is possible with minimal impact on public risk.

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

The NRC approved Amendment No. 104 (Reference 13), which modified the TS and facility operating license to adopt the performance based containment leak rate testing requirements

(Option B) of 10 CFR 50, Appendix J for Types A, B and C tests. Included in this amendment was the addition of the new TS 6.8.4.f, “Primary Containment Leakage Rate Testing Program.”

The NRC issued Amendment No. 134 (Reference 14), which revised the TS to permit an increase in the allowable leak rate for the MSIVs and to delete the MSIV Sealing System. These changes were based on the use of an alternate source term (AST) and the guidance provided in RG 1.183, "Alternate Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors."

The NRC issued Amendment No. 146 (Reference 15), which made use of the AST in the analysis of the fuel-handling accident and the LOCA to relax certain TS for containment isolation and to remove the Filtration Recirculation and Ventilation System - Recirculation Subsystem charcoal filters from the TS.

The NRC issued Amendment No. 147 (Reference 16), which revised the TS to allow a one-time extension of the Type A Integrated Leak Rate Test interval to 15 years. Additionally, this amendment included the following exception:

a. NEI 94-01-1995, Section 9.2.3: The first Type A test performed after April 12, 1994, shall be performed no later than April 12, 2009.

The NRC issued Amendment No. 174, regarding the Extended Power Uprate (EPU) for HCGS (Reference 17). The amendment increased the authorized maximum power level by approximately 15 percent, from the previously licensed thermal power of 3,339 megawatts thermal (MWt) to 3,840 MWt. Additionally, this amendment changed the peak calculated containment internal pressure for the design basis LOCA, P_a, from 48.1 psig to 50.6 psig.

3.4.4 Integrated Leakage Rate Testing History (ILRT)

As previously noted, the HCGS TS 6.8.4.f currently requires Types A, B, and C testing in accordance with RG 1.163, which endorses the methodology for complying with 10 CFR 50, Appendix J, Option B. Since the adoption of Option B, the performance leakage rates are calculated in accordance with NEI 94-01, Section 9.1.1 for Type A testing. Table 3.4.4-1 lists the past Periodic Type A ILRT results for HCGS.

Table 3.4.4-1 HCGS Type A Test History

Test Date	95% UCL Results (% weight per day)	As-Found Results (% weight per day)	As-Left Results (% weight per day)	Acceptance Criteria (% weight per day)
January 2, 1986	0.181	(1)	0.193	0.375
November 9, 1989	0.090	0.189	0.153	0.375
April 12, 1994	0.187	0.252	0.237	0.375
April 28, 2009 (2)	0.306	0.373	0.373	0.375

(1) The January 1986 test was a pre-operational test, therefore no “As-Found” results were required.

(2) The April 2009 Type A Test was performed at the post EPU P_a of 50.6 psig.

3.5 Plant Specific Confirmatory Analysis

3.5.1 Methodology

An evaluation has been performed to provide an assessment of the risk associated with implementing a permanent extension of the HCGS containment Type A ILRT interval from ten years to fifteen years. The risk assessment follows the guidelines from a number of documents, which include: NEI 94-01 (Reference 2); the methodology outlined in EPRI TR-104285 (Reference 7) as updated by the EPRI Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals (EPRI TR-1018243) (Reference 11); the NRC regulatory guidance on the use of Probabilistic Risk Assessment (PRA) findings and risk insights in support of changes to a plant’s licensing basis as outlined in RG 1.174 (Reference 3); and, 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 32). The format of this document is consistent with the intent of the Risk Impact Assessment Template for evaluating extended integrated leak rate testing intervals provided in the EPRI TR-1018243 (Reference 11).

Attachment 3 of this submittal contains details of the HCGS risk assessment, providing an assessment of the risk associated with implementing a permanent extension of the HCGS containment Type A ILRT interval from ten years to fifteen years.

The NRC report on performance-based leak testing, NUREG-1493 (Reference 6), 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 comparable boiling water reactor (BWR) plant, that increasing the containment leak rate from the nominal 0.5 percent per day to 5 percent per day leads to a barely perceptible increase in total population exposure, and increasing the leak rate to 50 percent per day increases the total population exposure by less than 1 percent. The current analysis is being performed to confirm these conclusions based on HCGS specific PRA models and available data.

Earlier ILRT frequency extension submittals have used the EPRI TR-104285 (Reference 7) methodology to perform the risk assessment. In October 2008, EPRI TR-1018243 (Reference 11) was issued to develop a generic methodology for the risk impact assessment for ILRT interval extensions to 15 years using current performance data and risk informed guidance, primarily NRC RG 1.174 (Reference 3). This more recent EPRI document considers the change in population dose, large early release frequency (LERF), and containment conditional failure probability (CCFP), whereas EPRI TR-104285 considered only the change in risk based on the change in population dose. This ILRT interval extension risk assessment for HCGS employs the EPRI TR-1018243 methodology, with the affected System, Structure, or Component (SSC) being the primary containment boundary.

In the Safety Evaluation (SE) issued by NRC letter dated June 25, 2008 (Reference 9), the NRC concluded that the methodology in EPRI TR-1009325, Revision 2, was acceptable for referencing by licensees proposing to amend their TS to permanently extend the ILRT surveillance interval to 15 years, subject to the limitations and conditions noted in Section 4.0 of the SE. Table 3.5.1-1 below addresses each of the four limitations and conditions from Section 4.2 for the use of EPRI TR-1009325, Revision 2.

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

Limitation and Condition (From Section 4.2 of SE)	HCGS Response
1. The licensee submits documentation indicating that the technical adequacy of their PRA is consistent with the requirements of RG 1.200 relevant to the ILRT extension application.	HCGS PRA technical adequacy is addressed in Section 3.5.2 of this LAR and Attachment 3, "Risk Assessment for HCGS Regarding the ILRT (Type A) Permanent Extension Request” Appendix A, "PRA Technical Adequacy."

Table 3.5.1-1, EPRI Report No. TR-1009325 Revision 2 Limitations and Conditions	
Limitation and Condition (From Section 4.2 of SE)	**HCGS 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.	Since the ILRT extension was demonstrated to have negligible impact on core damage frequency (CDF) for HCGS, the relevant criterion is LERF. The increase in internal events LERF resulting from a change in the Type A ILRT test interval for the base case with corrosion included is 3.91E-08/yr. In using the EPRI Expert Elicitation methodology, the change is estimated as 8.52E-09/yr. Both of these values fall within the "very small" change region of the acceptance guidelines in RG 1.174.
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 dose risk for changing the Type A test frequency from three-per-ten years to once-per-fifteen-years, measured as an increase to the total integrated dose risk for all internal events accident sequences for HCGS, is 5.15E-03 person-rem/yr (0.01%) using the EPRI guidance with the base case corrosion included. The change in dose risk drops to 1.38E-03 person-rem/yr (<0.01%) when using the EPRI Expert Elicitation methodology. The values calculated per the EPRI guidance are all lower than the acceptance criteria of ≤1.0 person-rem/yr or <1.0% person-rem/yr.
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 one in fifteen years including corrosion effects using the EPRI guidance is 0.93%. This value drops to 0.20% using the EPRI Expert Elicitation methodology. Both of these values are below the acceptance criteria of less than 1.5%.

Table 3.5.1-1, EPRI Report No. TR-1009325 Revision 2 Limitations and Conditions	
Limitation and Condition (From Section 4.2 of SE)	**HCGS Response**
3. The methodology in EPRI Report No. 1009325, Revision 2, is acceptable except for the calculation of the increase in expected population dose (per year of reactor operation). In order to make the methodology acceptable, the average leak rate accident case (accident case 3b) used by the licensees shall be 100 L_a instead of 35 L_a.	The representative containment leakage for Class 3b sequences used by HCGS is 100 L_a, based on the recommendations in the latest EPRI report (Reference 11) and as required in the NRC SE on this topic (Reference 9). It should be noted that this is more conservative than the earlier previous industry ILRT extension requests, which utilized 35 L_a for the Class 3b sequences.
4. A licensee amendment request (LAR) is required in instances where containment over-pressure is relied upon for ECCS performance.	HCGS does **NOT** rely upon containment over-pressure for ECCS performance. See Section 3.3 of this submittal for details.

3.5.2 Technical Adequacy of the PRA

The PRA Technical Adequacy evaluation is presented in Attachment 3, Appendix A, "PRA Technical Adequacy," of this LAR. The following is a summary of that evaluation.

3.5.2.1 Demonstrate the Technical Adequacy of the PRA

The guidance provided in RG 1.200 (Reference 4), 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.

The risk assessment performed for the ILRT extension request is based on the current Level 1 and Level 2 PRA model. Note that for this application, the accepted methodology involves a bounding approach to estimate the change in the PRA risk metric of Large Early Release Frequency (LERF) from extending the ILRT interval. Rather than exercising the PRA model itself, it involves the establishment of separate evaluations that are linearly related to the plant Core Damage Frequency (CDF) contribution. Consequently, a reasonable representation of the plant CDF that does not result in a LERF does not require that Capability Category II be met in every aspect of the modeling if the Category I treatment is conservative or otherwise does not significantly impact the results.

3.5.2.2 PRA Model Evolution and Peer Review Summary

The HC111A version of the HCGS PRA models are the most recent evaluations of the risk profile at HCGS for internal event challenges. The HCGS 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 HCGS PRA is based on the event tree / fault tree methodology, which is a well-known methodology in the industry.

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

3.5.2.3 PRA Maintenance and Update

The PSEG risk management process ensures that the applicable PRA model is an accurate reflection of the as-built and as-operated plants. This process is defined in the PSEG Risk Management program, which consists of a governing procedure and subordinate implementation procedures. The PRA model update procedure delineates the responsibilities and guidelines for updating the full power internal events PRA models at the operating PSEG sites. The overall PSEG Risk Management program defines the process for implementing regularly scheduled and interim PRA model updates, for tracking issues identified as potentially affecting the PRA models (e.g., due to changes in the plant, industry operating experience, etc.), and for controlling the model and associated computer files. To ensure that the current PRA model remains an accurate reflection of the as-built, as-operated plants, the following activities are routinely performed:

- Design changes and procedure changes are reviewed for their impact on the PRA model.
- Plant specific initiating event frequencies, failure rates, and maintenance unavailabilities are updated approximately every four years.

In addition to these activities, PSEG risk management procedures provide the guidance for particular risk management maintenance activities. This guidance includes:

- Documentation of the PRA model, PRA products, and bases documents.

- The approach for controlling electronic storage of Risk Management (RM) products including PRA update information, PRA models, and PRA applications.
- Guidelines for updating the full power, internal events PRA models for PSEG nuclear generation sites.
- Guidance for use of quantitative and qualitative risk models in support of the On-Line 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 (10 CFR 50.65(a)(4)).

In accordance with this guidance, regularly scheduled PRA model updates nominally occur on an approximately 4-year cycle; longer intervals may be justified if it can be shown that the PRA continues to adequately represent the as-built, as-operated plant. The HC111A models were completed in December of 2011. An analysis that evaluated plant modifications and procedure changes since 2011, all other Update Requirements Evaluations (UREs) and changing industry data was completed in 2015 concluded that the HCGS PRA continues to represent adequately the as-built, as-operated plant.

3.5.2.4 Plant Changes Not Yet Incorporated into the PRA Model

A PRA updating requirements evaluation (URE- HCGS PRA model update tracking database) is created for all issues that are identified that could impact the PRA model. The URE database includes the identification of those plant changes that could impact the PRA model.

A review of the open UREs indicates that there are no plant changes that have not yet been incorporated into the PRA model that would affect this application.

3.5.2.5 Consistency with Applicable PRA Standards

Several assessments of technical capability have been made for the HCGS internal events PRA models. These assessments are as follows and are further discussed in the paragraphs below.

- An independent PRA peer review (Reference 21) was conducted under the auspices of the BWR Owners Group in 2009, following the Industry PRA Peer Review process (Reference 33). This peer review included an assessment of the PRA model maintenance and update process.
- In January 2011, a self-assessment was performed against the available version of the ASME/ANS PRA Standard (Reference 30) in preparation for the HCGS 2011 PRA periodic update.

The HCGS PRA has previously undergone a thorough PRA Peer Review consistent with the NEI PRA Peer Review Guidelines (NEI 00-02 (Reference 23)). The results of that PRA Peer Review found that the PRA was capable of being used for risk-informed applications. The Capability Category and Findings and Suggestions results derived from the HCGS PRA Peer Review (see Note 1) were as follows:

- Capability Category
  - 96% of the Supporting Requirements were Capability Category II or III
  - 2% of the Supporting Requirements were Capability Category I
  - 2% of the Supporting Requirements were Not Met
- Facts and Observations
  - Findings: There were 15 Findings
  - Suggestions: There were 63 Suggestions

Note 1: The NEI 00-02 (Reference 23) grading scheme differs from that found in the ASME/ANS PRA Standard (Reference30).

This PRA Peer Review was used as an initial input into the PRA Self-Assessments relative to the combined ASME/ANS PRA Standard. There were 326 technical Supporting Requirements that were evaluated as part of the HC111A PRA related self-assessments. Of these 326 Supporting Requirements, the documentation and the model were judged to meet the ASME/ANS PRA Standard to support Capability Category II for all 326.

After the HC111A HCGS PRA update, the assessment of the PRA indicated the following results:

- Number of Supporting Requirements at Capability Category II or higher or Deemed Not Applicable — 326 of 326
- Number of Gaps Identified for HC111A PRA (Capability Category at I or Not Met) — 0

The HCGS model has no gaps identified as part of the self assessment process.

The HCGS HC111A PRA model is the result of updating the HCGS PRA model. As indicated above, a PRA model update was completed in 2011, resulting in the HC111A updated model. The PRA model assessments show that 100% of all the supporting requirements are characterized as meeting Capability Category II or better and all of the applicable Findings and Observations have been addressed.

3.5.2.6 Applicability of Peer Review Findings and Observations

Per the NRC SE (Reference 9) the appropriate PRA quality to support an ILRT risk assessment is that the PRA Standard Supporting Requirements should meet Capability Category I or greater. There are 316 Technical Supporting Requirements plus 10 Maintenance and Update Supporting Requirements in the Fire Protection Internal Events (FPIE) portion of the ASME/ANS PRA Standard (Reference 30).

Per the latest HCGS PRA Self-Assessment (Reference 22), there are no Supporting Requirements that are not met or addressed.

Attachment 3, Table A-1 of this submittal provides a summary of the HCGS PRA self-assessment (Reference 22), which identified no “gaps” to meeting Capability Category II of the

ASME/ANS PRA Standard (Reference 30) and RG 1.200, Rev. 2 (Reference 4). As detailed in Table A-1, no "gaps" fundamentally impact the conclusions of this ILRT extension application.

3.5.2.7 External Events

Although EPRI report 1018243 (Reference 11) recommends a quantitative assessment of the contribution of external events (for example, fire and seismic) where a model of sufficient quality exists, it also recognizes that the external events assessment can be taken from existing, previously submitted and approved analyses or another alternate method of assessing an order of magnitude estimate for contribution of the external event to the impact of the changed interval. Based on this, currently available information for external events models was referenced, and a multiplier was applied to the internal events results based on the available external events information. This is further discussed in Attachment 3, Section 5.7 of this submittal.

The current Fire PRA Model is considered adequate for risk insights, and other applications if limitations are understood and taken into account. The conservative nature of the Fire PRA modeling and the present status of Fire PRA development lead to these limitations (see section 5.7 for additional details). The HCGS Fire PRA was peer reviewed in 2010 and updated to address the peer review F&Os in 2015 (Reference 48). The results of the 2015 update are judged to be adequate to support the ILRT External Events quantitative risk assessment. Attachment 3, Table A-4 of this submittal summarizes the Fire PRA Peer Review results. The peer review focused on compliance to the ASME/ANS standard (Reference 30). Although not identified by the peer review team, there is believed to be conservatisms that can be addressed in future updates that will lead to an overall reduction in CDF contribution.

The Fire PRA Peer review did not identify issues that would preclude using the PRA results in performing an "order of magnitude" estimate for the ILRT risk assessment. Therefore, the quality of the Fire PRA is sufficient to support an order of magnitude HCGS ILRT external events risk impact assessment.

3.5.2.8 PRA Quality Summary

Based on the above, the HCGS PRA is of sufficient quality and scope for this application. The modeling is detailed; including a comprehensive set of initiating events (transients, LOCAs, and support system failures) including internal flood, system modeling, human reliability analysis and common cause evaluations. The HCGS PRA technical capability evaluations and the maintenance and update processes described above provide a robust basis for concluding that these PRA models are suitable for use in the risk-informed process used for this application.

3.5.2.9 Identification of Key Assumptions

The methodology employed in this risk assessment followed the EPRI guidance as previously approved by the NRC. The analysis included the incorporation of several sensitivity studies and factored in the potential impacts from external events in a bounding fashion. None of the sensitivity studies or bounding analysis indicated any source of uncertainty or modeling assumption that would have resulted in exceeding the acceptance guidelines. Since the

accepted process utilizes a bounding analysis approach which is mostly driven by that CDF contribution which does not already lead to LERF, there are no identified key assumptions or sources of uncertainty for this application (i.e. those which would change the conclusions from the risk assessment results presented here).

3.5.2.10 Summary

A PRA technical adequacy evaluation was performed consistent with the requirements of RG 1.200, Revision 2. This evaluation combined with the details of the results of this analysis demonstrates with reasonable assurance that the proposed extension to the ILRT interval for HCGS to fifteen years satisfies the risk acceptance guidelines in RG 1.174.

3.5.3 Summary of Plant-Specific Risk Assessment Results

The findings of the HCGS Risk Assessment contained in Attachment 3 of this submittal confirm the general findings of previous studies that the risk impact associated with extending the ILRT interval from three in ten years to one in fifteen years is small.

Based on the results from Attachment 3, Section 5.0, "Results," and the sensitivity calculations presented in Attachment 3, Section 6.0, "Sensitivities," the following conclusions regarding the assessment of the plant risk are associated with permanently extending the Type A ILRT test frequency to fifteen years:

- RG 1.174 (Reference 3) provides guidance for determining the risk impact of plant-specific changes to the licensing basis. RG 1.174 defines “very small” changes in risk as resulting in increases of CDF below 1.0E-06/yr and increases in LERF below 1.0E-07/yr. “Small” changes in risk are defined as increases in CDF below 1.0E-05/yr and increases in LERF below 1.0E-06/yr. Since the ILRT extension was demonstrated to have negligible impact on CDF for HCGS, the relevant criterion is LERF. The increase in internal events LERF resulting from a change in the Type A ILRT test interval for the base case with corrosion included is 3.91E-08/yr (See Attachment 3, Table 5.6-1). In using the EPRI Expert Elicitation methodology, the change is estimated as 8.52E-09/yr (See Attachment 3, Table 6.2-2). Both of these values fall within the “very small” change region of the acceptance guidelines in RG 1.174.

- The change in dose risk for changing the Type A test frequency from three-per-ten years to once-per-fifteen-years, measured as an increase to the total integrated dose risk for all internal events accident sequences for HCGS, is 5.15E-03 person-rem/yr (0.01%) using the EPRI guidance with the base case corrosion included (See Attachment 3, Table 5.6-1). The change in dose risk drops to 1.38E-03 person-rem/yr (<0.01%), when using the EPRI Expert Elicitation methodology (See Attachment 3, Table 6.2-2). The values calculated per the EPRI guidance are all lower than the acceptance criteria of ≤1.0 person-rem/yr or <1.0% person-rem/yr defined in Section 1.3.

- The increase in the conditional containment failure frequency from the three in ten year interval to one in fifteen years including corrosion effects using the EPRI guidance (See Attachment 3, Section 5.5) is 0.93%. This value drops to 0.20% using the EPRI Expert Elicitation methodology (See Attachment 3, Table 6.2-2). Both of these values are below the acceptance criteria of less than 1.5% defined in Section 1.3.

- To determine the potential impact from external events, a bounding assessment from the risk associated with external events was performed utilizing available information. As shown in Attachment 3, Table 5.7-6, the total increase in LERF due to internal events and the bounding external events assessment is 2.68E-07/yr. This value is in Region II of the RG 1.174 acceptance guidelines ("small" change in risk). The changes in dose risk and conditional containment failure frequency also remained below the acceptance criteria.

- As shown in Attachment 3, Table 5.7-7, the same bounding analysis indicates that the total LERF from both internal and external risks is 8.17E-06/yr which is less than the RG 1.174 limit of 1.0E-05/yr given that the ΔLERF is in Region II ("small" change in risk).

- Including age-adjusted steel liner corrosion effects in the ILRT assessment was demonstrated to be a small contributor to the impact of extending the ILRT interval for HCGS.

Therefore, 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 HCGS risk profiles.

3.5.4 Previous Assessments

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

- Reducing the frequency of Type A tests (i.e., ILRTs) from three per 10 years to one 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, increasing the interval between integrated leakage-rate tests is possible with minimal impact on public risk. The impact of relaxing the ILRT frequency beyond one in 20 years has not been evaluated. Beyond testing the performance of containment penetrations, ILRTs also test the integrity of the containment structure.

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

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

3.6 Non-Risk Based Assessment

Consistent with the defense-in-depth philosophy discussed in RG 1.174, HCGS has assessed other non-risk based considerations relevant to the proposed amendment. HCGS has multiple inspections and testing programs that ensure the containment structure remains capable of meeting its design functions and that are designed to identify any degrading conditions that might affect that capability. The following inspection and testing programs, limitations and conditions, along with other related items germane to the proposed activity are discussed below:

- 3.6.1 Safety-Related Coatings Inspection Program
- 3.6.2 Containment Inservice Inspection (CISI) Program
- 3.6.3 Primary Containment Leakage Rate Testing Program - Type B and Type C Testing Program
- 3.6.4 Type B and Type C Local Leak Rate Testing Program Implementation Review
- 3.6.5 Operating Experience
- 3.6.6 License Renewal Aging Management
- 3.6.7 Supplemental Inspection Requirements
- 3.6.8 NRC SER Limitations And Conditions

3.6.1 Safety-Related Coatings Inspection Program

HCGS has committed to follow RG 1.54, "Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants," Revision 0. The RG describes a method to comply with requirements of Appendix B to 10 CFR 50, and invokes several ANSI Standards. Standards pertinent to coatings used during initial construction were: ANSI N101.4-1972, "Quality Assurance for Protective Coatings Applied to Nuclear Facilities."

Since construction, PSEG is still committed to RG 1.54 Revision 0. RG 1.54 provides the Regulatory Position for compliance with Appendix B to 10 CFR Part 50 regarding the Quality Assurance (QA) requirements for protective coatings at a nuclear power facility. This RG refers to two specific documents, ANSI N101.4-1972 and ANSI N45.2-1971. PSEG endorses ANSI N101.4-1972 as guidelines for QA requirements for safety-related coatings.

In addition to these ANSI standards, ANSI N101.2-1972, N5.9-1967, and N5.12-1974 were developed to provide guidance for QA requirements for protective coatings applied in nuclear power facilities. All of these ANSI standards, with the exception of N45.2-1971, have been combined into one ASTM standard, ASTM D5144, “Standard Guide for Use of Protective Coating Standards in Nuclear Power Plants”.

This ASTM standard refers specifically to ASTM D3843, "Standard Practice for Quality Assurance for Protective Coatings Applied to Nuclear Facilities" for guidance in the application of Service Level I coatings (primary containment).

ASTM D3843 states that there are five major activities that should be controlled and documented as a minimum for Service Level I coatings;

1. Qualification and Selection of Coating Materials,
2. Coating Manufacturing,
3. Surface Preparation of Substrates,
4. Coating Application, and
5. Coating Inspection.

The PSEG coating program incorporates measures to ensure that these five activities are documented and controlled in accordance with PSEG standards.

During every refueling outage, a walkdown will be performed by individuals knowledgeable in nuclear coatings to make visual examinations and perform physical testing as necessary on the coatings to monitor their condition over time. The documentation of the results will be provided in a PSEG-Nuclear Civil Engineering inspection report.

Visual Coating Defect is defined as an adverse condition of a coating system, including, but not limited to blistering, cracking, flaking, peeling, delamination, and rusting. Blisters are areas that have detached from the substrate. Cracking is a condition where a break or split in the coating system extends through the film or to the substrate (from ASTM D3911) (Reference 20). Flaking and peeling are conditions where any coating layer, or any combination of layers detaches from its underlying layer or the substrate. Delamination is the separation of one coat or layer from another coat or layer, or from the substrate (from ASTM D3911). Rusting is a condition where the underlying metal substrate is incurring ferrous corrosion and is migrating through the coating system.

For Service Level I Coating Condition Monitoring Plan, all accessible areas of the drywell and torus should be planned to be inspected. Inspections of the submerged coatings in the torus will require coordination with the qualified diver contractor. An initial walk-through is required, followed by more thorough inspections on areas noted during the initial walk-through as being deficient. Any areas missed during the previous two inspection periods should take precedence during the inspection, provided that the areas can be accessed.

<u>Visual Examinations</u>

The individuals involved in the condition monitoring plan provide a close visual examination (at a distance of < 10 feet from the coating) of the coatings, particularly near the Emergency Core Cooling System (ECCS) strainers. Observations are to be documented in the Coatings Conditions Monitoring – Visual Examination Record. The individuals pay attention to the following conditions requiring maintenance:

- Blistering – use the pictorial standards in ASTM D 714 (Reference 34), and record the size and frequency of the blisters for each area measuring approximately 1 ft^2. If the actual blisters are larger than those shown on the pictorial standards, measure their diameter and frequency. For all blisters, note if they are intact, or separated from the substrate. Photographs are recommended.

- Cracking – Examine any cracking closely to determine if it is through one or more layers of the coating system, or all of the way to the substrate. Note the length and width of the crack (“hairline” may be appropriately used), and if there is more than one crack observed in a 1 ft^2 area. Note any observations for multiple 1-ft^2 areas in a given observation area. Note if the substrate, particularly for concrete, shows indications of cracks. Photographs are recommended.

- Flaking and Peeling – Observe areas of flaking and peeling are observed as small areas (less than 1 in^2) that separate as single or multiple coats from the substrate. For the purposes of this procedure, flakes are considered small inflexible areas (< 0.5 in^2) of coating separating from the surface, and peeling is the condition where the coating is semi-flexible and the areas are between 0.5 and 1 in^2. Using a hand tool such as a blade, attempt to peel the flaking or peeling coatings back to a sound substrate. Use a disposable plastic bag to discard the removed coatings. Photographs are recommended.

- Delaminations – are larger areas (> 1 in^2) of coatings separated from either each layer, or from the substrate. Attempt to remove the delamination with a hand tool and discard the debris into a plastic bag. For extensive delaminations, make a specific observation for a single notification for each specific observation. Photographs are recommended.

- Chipping – are areas in a sound coating system that have experienced mechanical impact or abrasions from tools, scaffolding, equipment, etc. Note areas and possible sources such as nearby scaffolding racks, or heavy equipment.

- Rusting – Use the pictorial standards in ASTM D 610 (Reference 35) or SSPC-VIS 2 (Reference 36) to determine the degree of rusting. Differentiate between rusting underneath the coating system (particularly with carbon steel substrates), or rusting on the surface from other sources.

If there are other visual observations not described above, note the approximate dimensions of the area, detail the observations for later research, and take a representative photograph. The information should be documented in the Coatings Conditions Monitoring – Visual Examination Record.

Any coating defects on the drywell and torus shell shall be brought to the attention of the responsible engineer for the ASME Section XI, Subsection IWE program.

<u>Impact of Coating Debris on the ECCS Suction Strainers</u>

The Vendor Technical Document (VTD) evaluates two load cases with respect to coating debris loading on the ECCS suction strainers. The base case considered 355lbs of coating debris,

consisting of 270 lbs of unqualified coatings and 85 lbs of paint chips. The second load case arbitrarily increased the quantity to 400 lbs of coating debris, consisting of an additional 45 lb of paint chips. The results of the increased loading resulted in no appreciable increase in the head loss (less than 0.05 ft-water) with respect to the base case. This calculation concluded that with these changes in the debris loading there would not be an adverse effect on total head loss.

The ECCS pump suction strainers have been designed to perform satisfactorily in the presence of 100% of the containment coatings which are installed in the LOCA pipe break steam/water jet zone of influence. This amount of coating debris is determined in accordance with the methodology documented in the BWR Owners' Group Utility Resolution Guidance (URG) document (NEDO-32686), Section 3.2.2.2.2.1.1. The conservative methodology used to establish the amount of coating debris has been accepted by the NRC, as documented in the Safety Evaluation Report (SER) on the URG dated August 20, 1998.

HCGS does not have licensing-basis requirements for tracking the amount of unqualified coatings inside the containment and for assessing the impact of potential coating debris on the operation of safety-related SSCs during a postulated design basis LOCA.

<u>Inspection Results</u>

RF16 Summary

PSEG performed a coating inspection of the steel and concrete surfaces on Elevation 86'-11" and 102' of the drywell. There were several small areas of mechanically-damaged coatings on both concrete and steel plates (bottom floor) which were all bounded by sound coatings. There was no evidence of active degrading coatings (i.e., peeling, delaminating, etc.).

However, there were areas requiring touch-up on the floor elevation.

RF17 Summary

Drywell:
All accessible areas of the drywell elevation 86'-11" and 100' 3" were visually inspected including the steel and concrete surfaces.

In general, the coating applied to the liner plate is essentially intact and providing corrosion protection to the steel substrate. Numerous coating repairs within the drywell implemented in the past are functioning well within design specifications.

There were small areas of mechanically bruised coating on both concrete and steel bottom surfaces, which were bounded by sound coatings needing no touch up work. These damages were mostly attributed to outage maintenance work. There was no evidence of active degrading coating (i.e., peeling, delamination and chipping etc.). There was little or no indication of rusting.

Torus:
Engineering performed a Service Level 1 coating inspection of the torus. Engineering walked down the torus and inspected the coatings from the catwalk. The coating system applied to the 16 bays of the torus vapor space walls displayed negligible level of coating damage.

The coating system applied to liner, vent pipes, vent header, down comers, spray header, and monorail was intact and free of significant coating damage. Some galvanized support members, including some of the hangars for the spray headers exhibited some rusting of zinc coating but need no touch up work at this time. The rusting is sound and does not easily flake away from the substrate. The surrounding galvanization is sound. There was no evidence of active degrading coating (i.e., peeling, delamination and chipping etc.).

Visual observations of underwater coating were performed from the catwalk and using flashlights directed to the torus pool. No flaking or peeling coatings from underwater substrates were observed. Underwater coatings appeared to be relatively sound with no indication of any appreciable defects.

As a result of RF17 inspections, there is no immediate concern for maintenance coating work in either the drywell or torus in RF17.

RF18 Summary

Torus:
Inspections of the Torus were performed by VT-1 and VT-3 certified inspectors.

The scope of work includes the following activities:

- Desludging of all 16 Bays (completed)
- Inspection for coatings in all bays (completed).

A total of 2249 indications were identified and the coating repair work started with bay 5 and part of the minor underwater coating repair work was completed. Remaining minor coating repairs may be performed in future outages when needed.

No major coating damages have been identified requiring immediate repairs such as flaking greater than Standard No.6 ASTM D 772 (Reference 37); blistering greater than No.4 and greater than 2" diameter ASTM D 714; No peeling, No discoloration, No checking greater than Standard ASTM D 660 (Reference 38); No cracking greater than No.6 ASTM D661 (Reference 40); No rusting greater than or equal to Grade 7 ASTM D610 (Reference 41). There are no signs of distress that will affect the containment structural integrity or leak tightness.

Separately, Engineering performed the 18-month walkdown of the torus and inspected the coatings from the catwalk. The coating system applied to the 16 bays of the torus vapor space walls displayed negligible level of coating damage.

Of the areas that were visible (above the water and from the catwalk), overall, the epoxy coating applied to the interior torus shell is in good condition, where there were minimal areas of impact damage and no disbandment or delamination apparent. Some of these locations were touched

up during previous outages and other small areas still show the bare metal. There was very light rusting on these bare areas of the carbon steel.

The center piping (down comers) showed the most impact damage and rust from small nicks on edges to larger scratches. The coatings surrounding the nicks and scratches were sound, thus no immediate maintenance is required. The galvanized coating on the catwalk and structures showed the most corrosion as it is losing its galvanizing properties and showing rust. This condition requires periodic assessment to determine whether cleaning of debris (rust, flaking zinc, etc.) is required.

The coating system applied to the liner, vent pipes, vent header, down comers, spray header, and monorail was intact and free of any significant coating damage. Some galvanized support members, including some of the hangars for the spray headers, exhibited some rusting of zinc coating, however, as explained earlier, their condition will be periodically monitored. The rusting is sound and does not easily flake away from the substrate. The surrounding galvanization is sound.

There is no immediate concern for maintenance coating work in torus.

Drywell:
Engineering performed a Service Level 1 coating inspection of the drywell elevation 86'-11" and 100' 3". All accessible areas were visually inspected including the steel and concrete surfaces. Overall, the coating system was holding well and there was no evidence of active degrading coating.

In RF18, HCGS installed a moisture barrier at the junction between the carbon steel drywell shell and the concrete floor slab at elevation 86' 11" (DCP 80097467 Rev 1 and WOs 60086265 and 60097742). As part of the moisture barrier installation, the coatings at the drywell and concrete floor were repaired to meet Service Level 1 standards, including materials, surface preparation, and the coating application was overseen by a NACE Level 3 Inspector. The inspector witnessed all mixing of products, atmospheric conditions, wet/dry film thickness of the coatings.

In general, the coating applied to the liner plate is essentially intact and providing corrosion protection to the steel substrate. Numerous coating repairs within the drywell implemented in the past are functioning well within design specifications.

There were small areas of mechanically bruised coating on both concrete and steel bottom surfaces, which were bounded by sound coatings needing no touch up work. These damages are mostly attributed to outage maintenance work. There was no evidence of active degrading coating (i.e., peeling, delamination and chipping etc.). There was little or no indication of rusting.

Based on the RF18 inspections, there is no immediate concern for maintenance coating work in either drywell or torus in RF18.

RF19 Summary

The scope of the inspections included the Service Level I coatings applied to the drywell shell, floor, piping, structural steel, and components, and the Service Level I coatings applied to the torus interior surfaces, piping, structural steel, and components.

All areas in the drywell at Elevation 87 - ft and 100 - ft were accessible. Binoculars were used to visually inspect the coatings above the 100 - ft elevation. The walkdowns started at Elevation 87 - ft in the drywell. In summary, the coatings are in good condition with no observations of blistering, peeling, flaking, checking, cracking, or delamination. There were observations of sporadic missing coatings that were caused by mechanical damage due to outage activities. There was one observed instance of corrosion on a baseplate on the floor of Elevation 87 - ft that should be repaired in a future outage. The small areas of missing coatings on the drywell shell should be planned for future touch up in accordance with the Primary Containment coating procedure.

All areas in the torus were accessible. The walkdown initiated at the entrance hatch at Azimuth 270. The walkdown was performed at the platform that runs the perimeter of the torus proper. Visual observations were made on the torus interior shell, including below the waterline. Flashlights were used to aid in the observations. Observations were also made on the piping, relief valves, downcomers, and structural steel. Overall, the coatings were in good condition. There were no observations of blistering, peeling, flaking, checking, cracking, or delamination.

There were observations of minor rusting on the exterior surfaces of the vent piping and relief valves where the coatings were mechanically damaged by tools, scaffolding, etc.

There were small areas of peeling galvanized coatings on the uni-strut members at the platform to 6-ft above the platform heights. Loose coatings were scraped back. The rust appeared to be adherent.

These specific areas are throughout the torus proper at the platform level. These areas will be recorded and recommended for future repair and touch-up in accordance with the Primary Containment coating procedure.

In general, the condition of the Service Level I coatings in the HCGS drywell and torus are in good condition. There are multiple areas coatings damaged by mechanical means (scaffolding, tools, etc.); however, the surrounding substrate is in good condition with no coatings peeling or delaminating from the point of damage.

3.6.2 Containment Inservice Inspection (CISI) Program

The Inservice Inspection (ISI) Program Plan details the requirements for the examination and testing of ISI Class 1, 2, 3, and MC pressure retaining components, supports, and containment structures at HCGS. The ISI Program Plan also includes Containment Inservice Inspection (CISI).

The third ISI interval and the second CISI interval for HCGS are effective from December 13, 2007 through December 12, 2017. The common ASME Section XI Code of Record for the third ISI Interval and the second CISI Interval is the 2001 Edition through the 2003 Addenda.

The third ISI Interval and the second CISI Interval are divided into three inspection periods as determined by calendar years within the intervals. Table 3.6.2-1 identifies the period start and end dates for the third ISI Interval and the second CISI Interval as defined by Inspection Program B. In accordance with Paragraph IWA-2430(d)(3), the inspection periods specified in these tables may be decreased or extended by as much as 1 year to enable inspection to coincide with the HCGS refueling outages.

Table 3.6.2-1

CISI INTERVAL/PERIOD/OUTAGE MATRIX

Interval	Periods	Outages	
Start Date To End Date	Start Date To End Date	Outage Dates and/or Durations	Outage Numbers
Second CISI Interval 12/13/07 to 12/12/17	1st 12/13/07 to 12/12/10	Scheduled 4/10/09 – 5/04/09 (24 d)	RF15
		Scheduled 10/15/10 – 11/11/10 (27 d)	RF16
	2nd 12/13/10 to 12/12/14	Scheduled 04/13/12 – 04/09/12 (25.9 d)	RF17
		Scheduled 10/11/13 – 11/10/13 (29.6 d)	RF18
	3rd 12/13/14 to 12/12/17	Scheduled 04/10/15 – 05/12/15 (32 d)	RF19
		Scheduled October, 2016	RF20

Table 3.6.2-1 CISI INTERVAL/PERIOD/OUTAGE MATRIX			
Interval	Periods	Outages	
Start Date To End Date	Start Date To End Date	Outage Dates and/or Durations	Outage Numbers
Third CISI Interval (1) 12/13/17 to 12/31/26	1st 12/13/17 to 12/12/20	Projected April, 2018	RF21
		Projected October, 2019	RF22
	2nd 12/13/20 to 12/12/24	Projected April, 2021	RF23
		Projected October, 2022	RF24
	3rd 12/13/24 to 12/31/26	Projected April, 2024	RF25
		Projected October, 2026	RF26

(1) The dates for the third CISI Interval are postulated dates as the third CISI Interval plan has yet to be approved.

First Interval CISI Program

The CISI Program Plan was developed, and examinations commenced on April 22, 2000, with all First Period CISI examinations being completed during RF9 (prior to May 24, 2000), which fully satisfied the September 9, 2001 expedited implementation requirement.

Examinations for the Second Period of the CISI Program were completed during RF10 in the Fall of 2001, and RF11 in the Spring of 2003, respectively.

Third CISI Period examinations were completed during RF12 in the Fall of 2004, and RF13 during the spring of 2006; with the remainder scheduled for completion in RF14, during the Fall of 2007.

Therefore all First CISI Interval examinations were scheduled to be completed prior to December 12, 2007; concurrent with the end date for the Second ISI Interval. As detailed in the submittal of the Third Interval ISI Program, the transition from the First CISI Interval to the Second CISI Interval coincides with the transition from the Second ISI Interval to the Third ISI Interval to provide a common interval start and end date and Code of record between the ISI and CISI Programs.

No significant examination issues were identified in this First CISI Interval requiring application of additional augmented examination requirements as detailed within Paragraph IWE-1240.

Second Interval CISI Program

Pursuant to 10 CFR 50.55a(g), licensees are required to update their CISI Programs to meet the requirements of ASME Section XI once every ten years or inspection interval. The CISI Program is required to comply with the latest Edition and Addenda of the Code incorporated by reference in 10 CFR 50.55a twelve months prior to the start of the interval per 10 CFR 50.55a(g)(4)(ii). The start of the Second CISI Interval was on December 13, 2007 for HCGS. Based on this date, the latest Edition and Addenda of the Code referenced in 10 CFR 50.55a(b)(2) twelve months prior to the start of the Second CISI Interval was the 2001 Edition through the 2003 Addenda.

The HCGS Second Interval CISI Program Plan was developed in accordance with the requirements of 10 CFR 50.55a including all published changes through February 19, 2006, and the 2001 Edition through the 2003 Addenda of ASME Section XI, subject to the limitations and modifications contained within Paragraph (b) of the regulation. These limitations and modifications are detailed in Table 3.6.2-2 of this section. This Second Interval CISI Program Plan addresses Subsection IWE, Mandatory Appendices, approved Code Cases, approved alternatives through relief requests and SERs, and utilizes Inspection Program B as defined therein.

The HCGS Second CISI Interval is effective from December 13, 2007 through December 12, 2017.

Code of Federal Regulations 10 CFR 50.55a Requirements

There are certain paragraphs in 10 CFR 50.55a that list the limitations, modifications, and/or clarifications to the implementation requirements of ASME Section XI. These paragraphs in 10 CFR 50.55a that are applicable to the HCGS scheduled CISI examination programs are detailed in Table 3.6.2-2.

Table 3.6.2-2

CODE OF FEDERAL REGULATIONS 10 CFR 50.55a REQUIREMENTS

10 CFR50.55a Paragraphs	Limitations, Modifications, and Clarifications
10 CFR 50.55a(b)(2)(ix)(A)	(CISI) Examination of metal containments and the liners of concrete containments: For Class MC applications, the licensee shall evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of or result in degradation to such inaccessible areas. For each inaccessible area identified, the licensee shall provide the following in the ISI Summary Report as required by IWA-6000: (1) A description of the type and estimated extent of degradation, and the conditions that led to the degradation; (2) An evaluation of each area, and the result of the evaluation, and; (3) A description of necessary corrective actions.
10 CFR 50.55a(b)(2)(ix)(B)	(CISI) Examination of metal containments and the liners of concrete containments: 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 3.6.2-2 CODE OF FEDERAL REGULATIONS 10 CFR 50.55a REQUIREMENTS	
10 CFR50.55a Paragraphs	**Limitations, Modifications, and Clarifications**
10 CFR 50.55a(b)(2)(ix)(F)	(CISI) Examination of metal containments and the liners of concrete containments: VT-1 and VT-3 examinations must be conducted in accordance with IWA-2200. Personnel conducting examinations in accordance with the VT-1 or VT-3 examination method shall be qualified in accordance with IWA-2300. The “owner-defined” personnel qualification provisions in IWE-2330(a) for personnel that conduct VT-1 and VT-3 examinations are not approved for use.
10 CFR 50.55a(b)(2)(ix)(G)	(CISI) Examination of metal containments and the liners of concrete containments: The VT-3 examination method must be used to conduct the examinations in Items E1.12 and E1.20 of Table IWE-2500-1, and the VT-1 examination method must be used to conduct the examination in Item E4.11 of Table IWE-2500-1. An examination of the pressure-retaining bolted connections in Item E1.11 of Table IWE-2500-1 using the VT-3 examination method must be conducted once each interval. The “owner-defined” visual examination provisions in IWE-2310(a) are not approved for use for VT-1 and VT-3 examinations.
10 CFR 50.55a(b)(2)(ix)(H)	(CISI) Examination of metal containments and the liners of concrete containments: Containment bolted connections that are disassembled during the scheduled performance of the examinations in Item E1.11 of Table IWE-2500-1 must be examined using the VT-3 examination method. Flaws or degradation identified during the performance of a VT-3 examination must be examined in accordance with the VT-1 examination method. The criteria in the material specification or IWB-3517.1 must be used to evaluate containment bolting

Table 3.6.2-2 CODE OF FEDERAL REGULATIONS 10 CFR 50.55a REQUIREMENTS	
10 CFR50.55a Paragraphs	**Limitations, Modifications, and Clarifications**
	flaws or degradation. As an alternative to performing VT-3 examinations of containment bolted connections that are disassembled during the scheduled performance of Item E1.11, VT-3 examinations of containment bolted connections may be conducted whenever containment bolted connections are disassembled for any reason.
10 CFR 50.55a(b)(2)(ix)(I)	(CISI) Examination of metal containments and the liners of concrete containments: The ultrasonic examination acceptance standard specified in IWE-3511.3 for Class MC pressure-retaining components must also be applied to metallic liners of Class CC pressure-retaining components.

CONTAINMENT ISI PLAN

The HCGS Containment ISI Plan includes ASME Section XI ISI Class MC pressure retaining components and their integral attachments. This Containment ISI Plan also includes information related to augmented examination areas, component accessibility, and examination review.

Nonexempt ISI Class Components

The HCGS ISI Class MC components identified are those not exempted under the criteria of Paragraph IWE-1220 in the 2001 Edition through the 2003 Addenda of ASME Section XI. A summary of the HCGS ASME Section XI nonexempt CISI components is included in Table 3.6.2-3.

Components that are classified as ISI Class MC, must meet the requirements of ASME Section XI in accordance with 10 CFR 50.55a(g)(4). Although supports of IWE components are not strictly required to be examined in accordance with 10 CFR 50.55a(g)(4)(v), HCGS has elected to perform these examinations in accordance with ASME Section XI, Subsection IWF.

Table 3.6.2-3 INSERVICE INSPECTION SUMMARY TABLE					
Examination Category (with Examination Category Description)	**Item Number**	**Description**	**Exam Requirements**	**Total Number of Components**	**Notes**
E-A Containment Surfaces	E1.11	Containment Vessel Pressure Retaining Boundary – Accessible Surface Areas	General Visual	256	
	E1.11	Containment Vessel Pressure Retaining Boundary – Bolted Connections, Surfaces	Visual, VT-3	30	5
	E1.12	Containment Vessel Pressure Retaining Boundary – Wetted Surfaces of Submerged Areas	Visual, VT-3	22	6
	E1.20	Containment Vessel Pressure Retaining Boundary – BWR Vent System Accessible Surface Areas	Visual, VT-3	18	6
	E1.30	Moisture Barriers	General Visual	1	
E-C Containment Surfaces Requiring Augmented Examinations	E4.11	Containment Surface Areas - Visible Surfaces	Visual, VT-1	1	7
	E4.12	Containment Surface Areas - Surface Area Grid Minimum Wall Thickness Location	Ultrasonic Thickness	1	7, 12

(5) Bolted connections examined per Item Number E1.11 require a General Visual examination each period and a VT-3 visual examination once per interval and each time the connection is disassembled during a scheduled E1.11 examination. Additionally, a VT-1 visual examination shall be performed if degradation or flaws are identified during the VT-3 visual examination. These modifications are required by 10 CFR 50.55a(b)(2)(ix)(G) and 10 CFR 50.55a(b)(2)(ix)(H).

(6) Item Numbers E1.12 and E1.20 require VT-3 visual examination in lieu of General Visual examination, as modified by 10 CFR 50.55a(b)(2)(ix)(G).

(7) Item Number E4.11 requires VT-1 visual examination in lieu of Detailed Visual examination, as modified by 10 CFR 50.55a(b)(2)(ix)(G).

(12) Perform augmented IWE ultrasonic thickness (UT) measurements of the drywell shell between elevation 86'-11" (floor of the drywell concrete) and elevation 93' (bottom of penetration J13) and below penetration J13 area. In addition, UT measurements will also be performed around the full 360 degree circumference of the drywell between elevations 86'-11" and 88'-0" (underside of the torus down comer vent piping penetrations).

UT thickness measurements shall be performed each refuel outage until drainage has been established at the bottom of the air gap from all four drains, and then for the next three refueling outages. The UT thickness measurements will be taken in each refueling outage starting with RF17, using the same location as those examined in 2010 refueling outage.

Augmented Examination Areas

The containment section of the ISI Classification Basis Document discusses the containment design and components. Metal containment surface areas subject to accelerated degradation and aging require augmented examination per Examination Category E-C and Paragraph IWE-1240.

A significant condition is a condition that is identified as requiring application of additional augmented examination requirements under Paragraph IWE-1240. No significant conditions were identified in the First CISI Interval. Conditions are currently identified in the Second CISI Interval as requiring application of additional augmented examination requirements under Paragraph IWE-1240 as a result of license renewal.

For license renewal, augmented IWE UT measurements of the drywell shell between elevation 86'-11" (floor of the drywell concrete) and elevation 93' (bottom of penetration J13) and below penetration J13 area are required. In addition, UT measurements will also be performed around the full 360 degree circumference of the drywell between elevations 86'-11" and 88'-0" (underside of the torus down comer vent piping penetrations).

UT thickness measurements shall be performed each refuel outage until drainage has been established at the bottom of the air gap from all four drains, and then for the next three refueling outages. The UT thickness measurements will be taken in each refueling outage starting with RF17, using the same location as those examined in the 2010 refueling outage. These UT thickness measurements shall be compared to the results of the initial UT inspections performed in the 2010 refueling outage. The results of the UT measurements will be used to identify drywell surfaces requiring augmented inspections in accordance with IWE requirements and to establish corrosion rates, both prior to establishing air gap drainage and after establishing drainage. The UT thickness measurement results shall be forwarded to engineering for evaluation.

> Note: The results of UT thickness measurements are discussed in Inspection Results for 1RF17, 1RF18 and 1RF19 "License Renewal Commitment Implementation" discussions below.

Relief Requests from ASME Section XI

There are no relief requests associated with the CISI Program at HCGS.

Inspection Results

RF16 Summary

There were no items with flaws or relevant conditions that required evaluation for continued service.

RF17 Summary

There were no items with flaws or relevant conditions that required evaluation for continued service.

License Renewal Commitment Implementation (Reference 12)

The Renewed Operating License No. NPF-57 for HCGS was issued on July 20, 2011. The renewed license included several license conditions related to the ASME Section XI, Subsection IWE aging management program and, in particular, to the HCGS drywell air gap drains. License Condition (26) requires that drainage capability from the bottom of the drywell air gap be established on or before June 30, 2015. Activities to establish or verify these drains were included in the scope of Refueling Outage (RF) 17 and were worked during the outage that began on April 13, 2012 and ended on May 9, 2012.

The relevant license conditions are contained in Section 2.C of the renewed license and read as follows:

> (26) The licensee will establish drainage capability from the bottom of the drywell air gap on or before June 30, 2015. The licensee will divide the drywell air gap into four

approximately equal quadrants. Drainage consists of one drain in each quadrant for a total of four drains. Each drain will be open at the bottom of the drywell air gap and be capable of draining water from the air gap.

Until drainage is established from all ·four quadrants, the licensee will perform the following actions each refueling outage:

a. Perform boroscope examination of the bottom of the drywell air gap through penetrations located at elevation 93'-0" in four quadrants, 90 degrees apart. The personnel performing the boroscope examination shall be certified as VT-1 inspectors in accordance with ASME Section XI, Subsection IWA-2300, requirements. The examiners will look for signs of water accumulation and drywell shell corrosion. Adverse conditions will be documented and addressed in the corrective action program.

b. Perform UT measurements of the drywell shell between elevations 86'-11" (floor of the drywell concrete) and 93' -0" (bottom of penetration J13) below penetration J13 area. In addition, UT measurements shall be performed around the full 360 degree circumference of the drywell between elevations 86'-11" and 88'-0" (underside of the torus down comer vent piping penetrations). The results of the UT measurements shall be used to establish a corrosion rate and demonstrate that the effects of aging will be adequately managed such that the drywell can perform its intended function until April 11, 2046. Evidence of drywell shell degradation will be documented and addressed in the corrective action program.

c. Monitor penetration sleeve J13 daily for water leakage when the reactor cavity is flooded up. In addition, perform a walkdown of the torus room to detect any leakage from other drywell penetrations. These actions shall continue until corrective actions are taken to prevent leakage through J13.

d. Within 90 days of completion of each refueling outage, submit a report to the NRC staff in accordance with 10 CFR 50.4 summarizing the results from the boroscope examinations, UT measurements, leakage detected from penetrations, and if appropriate, corrective action.

(27) After drainage has been established from the bottom of the air gap in all four quadrants, the licensee will:

a. Submit a report to the NRC staff in accordance with 10 CFR 50.4 describing the final drain line configuration and summarizing the testing results that demonstrate drainage has been established for all four quadrants.

b. Monitor penetration sleeve J13 daily for water leakage when the reactor cavity is flooded up. In addition, perform a walkdown of the torus room to detect any leakage from other drywell penetrations. These actions shall continue until corrective actions are taken to prevent leakage through J13 or through the four air gap drains.

c. Perform UT measurements of the drywell shell between elevation 86'-11" (floor of the drywell concrete) and elevation 93'-0" (bottom of penetration J13) below penetration J 13 area during the next three refueling outages. In addition, UT measurements shall be performed around the full 360 degree circumference of the drywell between elevations 86'-11" and 88'-0" (underside of the torus down comer vent piping penetrations). The results of the UT measurements will be used to identify drywell surfaces requiring augmented inspections in accordance with IWE requirements for the period of extended operation, establish a corrosion rate, and demonstrate that the effects of aging will be adequately managed such that the drywell can perform its intended function until April 11, 2046. Within 90 days of completion of each refueling outage, submit a report to the NRC staff in accordance with 10 CFR 50.4 summarizing the results from the UT measurements and if appropriate, corrective action.

Summary of Commitment Implementation

The specific license conditions addressed and/or resolved during the HCGS RF17 Refueling Outage are as follows:

A. Air Gap Drain Functionality (License Condition 26 satisfied)

Activities performed prior to and during the RF17 HCGS refueling outage have confirmed that there are four functional drains from the air gap as described in Technical Evaluation 80106392.

In February, 2012, three drain pipes were boroscopically examined to confirm that they are clear and able to port any leakage into the air gap away from the drywell shell. These drain lines are located at azimuths 80, 160 and 340 degrees.

During the RF17 refueling outage, the excavated tunnel at the 250 degree azimuth was inspected to confirm that the tunnel was slopped such that it would port any leakage into the air gap away from the drywell shell (a second excavated tunnel at azimuth 120 degrees was also inspected and confirmed that it was sloped to port any leakage into the air gap away from the drywell). Grout was added as necessary at both tunnels to ensure a continuous flow path for leakage.

As a result of these activities and the boroscopic examinations described in the next paragraph, the three drains and the tunnel at the 250 azimuth were declared functional drains to satisfy license condition 26. The tunnel at the 120 azimuth was also confirmed to be a functional drain. This satisfies the license condition to have functional drains in each of four approximately equal quadrants around the drywell air gap.

B. Boroscope Examinations (License Condition 26a satisfied)

The boroscopic examinations of the bottom of the drywell air gap through the penetrations located at elevation 93' in four quadrants, 90 degrees apart, were performed by certified VT-1 inspectors in accordance with ASME Section XI, Subsection

IWA-2300 requirements. The videos have been reviewed to confirm there was no water evident at the bottom of the air gap.

Boroscopic examinations were also performed from the excavated tunnels horizontally around the bottom of the air gap to confirm the configuration of the intersection of the drain piping with the air gap. Two of the three drain pipes were examined to confirm that the drains were functional and would port any leakage away from the drywell shell.

C. UT Measurements (License Condition 26b satisfied and License Condition 27c partially satisfied)

The UT measurements prescribed by this license condition were performed. No significant corrosion to the drywell shell is occurring.

The UT measurements taken during RF16 were used as baseline readings and have no wall thinning as compared to the readings taken in RF17, it is not possible to calculate a plant-specific corrosion rate so industry data will be used. Three water samples were taken from the J 13 and J 14 penetration sleeves in RF16 and water samples were taken from J13 and J19 penetration in RF17 (no water was observed from the J14 penetration in RF17). The pH ranged from 8.3 to 8.5 in RF16, and 8.1 in RF17, consistent with water flowing down bare concrete, and the water reaching the bottom of the drywell air gap would be similar. Water in this pH range (i.e. basic) has a lower potential to cause corrosion than acidic water. The outer surface of the drywell shell is coated with an inorganic zinc coating to prevent corrosion. The coating was noted in good condition during boroscope examinations around the penetrations, air gap bottom, and inspection of the tunnels. There is no observed corrosion occurring on the drywell shell.

UTs were performed in RF16 and RF17 for the full circumference along the junction of the concrete floor and the drywell shell. The bottom of the drywell air gap is on the other side of this junction. No notable or significant shell thinning was observed.

UTs were also performed on the drywell shell at the 225 degree azimuth below the group of 6 penetrations (including penetrations J13 and J14). The lowest UT on the plate below the group penetrations was 1.475" in RF16 and 1.470 in RF17. Comparing these measurements to the analysis limit of 1.4375" proves that 37.5 mils thickness margin remained in RF16 and the current margin (from UTs taken during RF17) is 32.5 mils thickness margin. At a conservative corrosion rate of 5 mils per cycle the analysis limit would not be reached for over 9 cycles. The actual design limit is below the analysis limit. It should be noted that the lower readings on this 1.5" plate could be due to either original construction tolerances or potential minor corrosion.

Therefore, there is no significant corrosion to the drywell shell below the J13 penetration sleeve at 225 degree azimuth due to periodic exposure to reactor cavity water. Additionally, reactor cavity water reaching the bottom of the drywell air gap is not causing significant corrosion to the drywell shell at the interface of the floor, the air gap, and the drywell shell.

In accordance with the HCGS Renewed Facility Operating License Condition 2.C.27, UT thickness measurements will be taken of the drywell shell below the J13 penetration sleeve area and around the full 360 degree circumference of the drywell between elevations 86'-11" and 88'-0" for the three refueling outages following establishing drainage from the bottom of the air gap from all four drains. These UT measurements will be compared to the results of the previous UT inspections to determine if corrosion is ongoing and to determine a corrosion rate. In the event a significant corrosion rate is detected, the condition will be entered into the corrective action process.

D. Monitoring of J13 Penetration Sleeve (License Conditions 26c and 27b satisfied)

During RF17, the J13 penetration sleeve was monitored daily for water leakage while the reactor cavity was flooded up (April 17 through April 30, 2012). In addition, the penetrations adjacent to penetration J13, the three open air gap drains and the excavated construction tunnels at 250 degree azimuth and 120 degree azimuth were monitored daily for water leakage while the reactor cavity was flooded up.

Walkdowns were also performed in the Torus Room to confirm that there was no leakage from other penetrations.

During the walk downs following reactor cavity flood-up, water was observed leaking from penetration sleeves at 225 degree azimuth (the vicinity of the J13 penetration) and the excavated access tunnel located between 250 and 290 degree azimuths. On April 20 and 21, leakage was identified from penetration sleeve J13, the leak rate varied from 6 drops per minute to 10 drops per minute. This coincided with a slow leak noted coming from the air gap in the construction tunnel at 250 degree azimuth. No water was noted leaking from any other areas. From April 22 to April 25, there was no evidence of active leakage from the J13 area, the 250 degree azimuth tunnel or other various areas. On April 26, approximately 4 drops per minute leakage was observed coming out of the J19 penetration sleeve (note: penetration J13, J14 and J19 are at the same elevation and are separated approximately 25 inches. Again, leakage from the J19 penetration area (225 degree azimuth, elevation 95'-3") coincided with noted moisture on the ledge at the entrance to the 250 degree azimuth tunnel.

No other leakage was observed from other air gap penetration sleeves, there was no sign of leakage from the end of the three drywell air gap drains (at 80, 160 and 340 degree azimuths) and there was no evidence of water leakage from the excavated tunnel at 120 degree azimuth. The Reactor Cavity to Drywell Seal Rupture Drain Alarm did not actuate. The leakage stopped when the reactor cavity was drained.

Conclusion

All activities associated with HCGS renewed operating license conditions 2.C.26 and 2.C.27 that were required to be completed during the RF17 refueling outage were completed. Activities completed prior to and during the outage have confirmed the presence of four functional air gap drains thus satisfying license condition 2.C.26.

Implementation activities required per license condition 2.C.27 will continue into the next refueling outage.

RF18 Summary

Torus Internal Examination:

Coating discrepancy with rusting present was identified. An evaluation for continued service was performed . The areas identified are nonstructural in nature and there was no unacceptable effect on the structural integrity of the torus shell. These areas were found acceptable for continued service under the requirements of IWE-3510.2 and will require reexamination under IWE-2420 during the next inspection Period (RF19 or RF20) and coatings repair to eliminate future shell degradation as described in IWE-3122.2, and replacement of the lost coatings required by IWE-1241.

License Renewal

Summary of Commitment Implementation:

The specific license conditions addressed and/or resolved during RF18 are as follows:

A. Monitoring of J13 Penetration Sleeve (License Condition 2.C.(27)b)

During RF18, the J13 penetration sleeve was monitored daily for leakage while the reactor cavity was flooded up (October 15 through October 31, 2013). Further, the penetrations adjacent to penetration J13 (J19, J14, J29, J24, and J37, specified here as the “J13 penetration group”) and the air gap drains were monitored daily for water leakage. In addition, a full walkdown of the torus room was performed to confirm there was no leakage from any other penetrations. During the walkdowns following reactor cavity flood-up and continuing until reactor cavity drain down, water was observed at the 225 degree azimuth from the J13 penetration group (specifically the J19 penetration) as well as the excavated access tunnel located at 250 degree azimuth (credited air gap drain).

On October 17, 2013, leakage was identified from penetration sleeve J19 at a leak rate of approximately 20 drops per minute. Note that penetrations J13 and J19 are at the same elevation and are separated by approximately 25 inches. No water was noted leaking from other areas within the torus room. On October 18, 2013, approximately 20 drops per minute leakage was observed coming out of the excavated access tunnel at 250 degree azimuth, in addition to the aforementioned leakage from the J19 penetration sleeve, which had continued. The last recorded active leakage from the 250 degree azimuth access tunnel was October 27, 2013. Although the area was “wet” during the October 31, 2013, walkdown, no active leakage was noted. Likewise, the last recorded leakage from penetration sleeve J19 was October 31, 2013.

It was concluded that the leakage observed during RF18 was similar to that observed in RF17. No leakage was observed from other air gap penetration sleeves and there was

no sign of leakage from the end of the other three drywell air gap drains (at 80, 160 and 340 degree azimuths) or from the excavated tunnels at 290, 155 and 115 degree azimuths. The Reactor Cavity to Drywell Seal Rupture Drain Alarm did not actuate. All leakage stopped when the reactor cavity was drained.

B. UT Measurements (License Condition 2.C.(27)c)

The UT measurements prescribed by license condition 2.C.(27)c were performed during RF18. Based on the consistency of the UT measurements with those taken in previous outages, PSEG has concluded that no corrosion is occurring on the drywell shell.

UT measurements were performed on the drywell shell at the 225 degree azimuth between 86'-11" and 93'-0" elevation (below the J13 penetration group). The lowest UT measurements occurred on a plate below the J13 penetration group and measured 1.475" in RF16, 1.470" in RF17 and 1.471" in RF18. Note that these readings were not at the same measurement point but were the lowest of all recorded readings taken during the respective outages. Comparing the lowest reading of 1.470" to the analysis limit of 1.4375" proves that at least 32.5 mils thickness margin remains. Further, the consistency of the thickness measurements proves that no corrosion to the drywell shell is occurring below the J13 penetration group. It should be noted that during development of the HCGS license renewal application, PSEG concluded that the cause of the lower readings on this plate were due to the plate's construction tolerances being at the lower end, but acceptable for use.

UT measurements were also performed for the full circumference of the drywell shell between elevations 86'-11" and 88'-0". The bottom of the drywell air gap is on the outside of the drywell shell between these elevations. The lowest UT measurements at the bottom of the drywell were 1.480" in RF16, 1.477" in RF17 and 1.471" in RF18. Note that these readings were not at the same measurement point but were the lowest of all recorded readings taken during the respective outages. Comparing the lowest reading of 1.471" to the analysis limit of 1.4375" shows that 33.5 mils thickness margin remains. Based on the consistency of these UT measurements, PSEG has concluded that no corrosion is occurring in the drywell shell at the bottom of the drywell air gap. Nevertheless, even if a very conservative corrosion rate of 6 mils per cycle were to be assumed, the analysis limit of 1.4375 would not be reached for at least 5 cycles. The UT measurements will be taken again during the RF19 outage to confirm that no corrosion is occurring in the drywell shell.

The UT measurement activities required to be completed during RF18 by license condition 2.C.(27)c were completed as described above. License condition 2.C.(27)c requires these UT measurement activities for the three refueling outages following establishment of drainage capability from the bottom of the drywell air gap. RF18 is the first of these outages. Therefore, these UT measurement activities will continue for the next two refuel outages. Results of the UT measurement activities will be compared to the previous UT measurement results to determine if any corrosion is occurring and to determine a corrosion rate if corrosion is identified. Should a significant corrosion rate be detected, the condition will be entered into the corrective action process for resolution.

Conclusion

The actions taken by PSEG during RF18 to satisfy license condition 2.C.(27)b. and 2.C.(27)c. were submitted by PSEG Letter No. LR-N14-0029 (Reference 42). The results of the UT measurements demonstrate there were currently no drywell surfaces requiring augmented inspections in accordance with IWE requirements for the period of extended operation.

RF19 Summary

There were no items with flaws or relevant conditions that required evaluation for continued service.

License Renewal

Summary of Commitment Implementation:

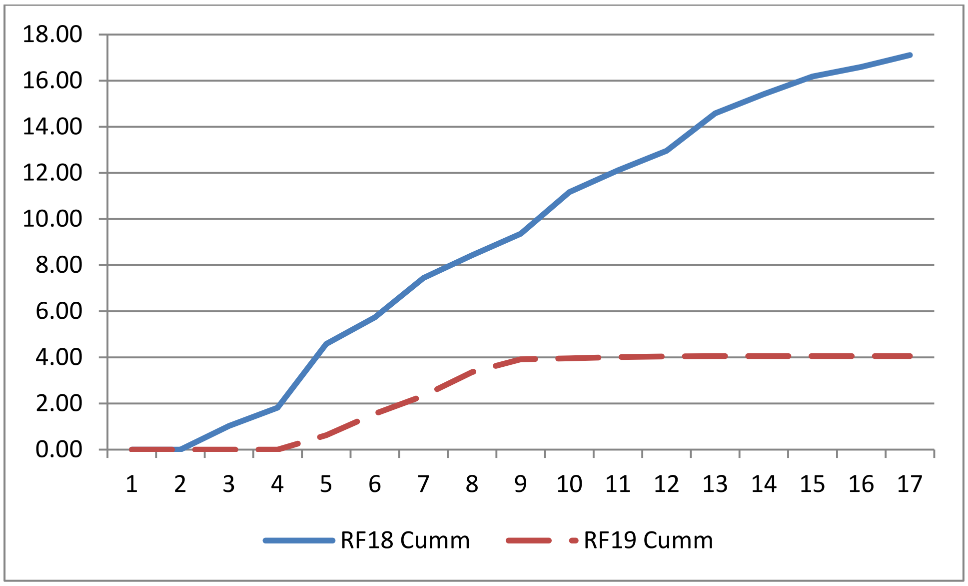
The specific license conditions addressed and/or resolved during RF19 are as follows:

A. Monitoring of J13 Penetration Sleeve (License Condition 2.C.(27 b.)

During RF19, the J13 penetration sleeve was monitored daily for leakage while the reactor cavity was flooded up (April 13, 2015 through April 30, 2015). Further, the penetrations adjacent to penetration J13 (J19, J14, J29, J24, and J37, specified here as the “J13 penetration group”) and the air gap drains were monitored daily for water leakage. In addition, a full walk-down of the torus room was performed to confirm there was no leakage from any other penetrations. Walk-downs were performed daily while the reactor cavity was flooded by Operations in accordance with Operating Procedure HC.OP-IO.ZZ-0005, COLD SHUTDOWN TO REFUELING, and by Engineering. During the walk-downs following reactor cavity flood-up and continuing until reactor cavity drain down, water was observed at the 225 degree azimuth from the J13 penetration group (specifically the J19 penetration) as well as the excavated access tunnel located at 250 degree azimuth (credited air gap drain).

On April 17, 2015, leakage was identified from penetration sleeve J19 at a leak rate of approximately 42 drops per minute. Note that penetrations J13 and J19 are at the same elevation and are separated by approximately 25 inches. No water was noted leaking from any other areas within the torus room. The leak rate from the J19 penetration remained at or around 42 drops per minute through April 20, 2015. On April 20, 2015 leakage was also observed coming out of the excavated access tunnel at 250 degree azimuth. The leakage from the 250 tunnel was estimated to be approximately 10 drops per minute. On April 21, 2015 the 250 tunnel leakage remained at approximately 10 drops per minute while the penetration J19 leakage dropped to approximately 20 drops per minute. On April 22, 2015 the leakage from the 250 tunnel ceased and the leakage from the penetration J19 diminished to approximately 2 drops per minute. The leakage from the 250 tunnel never returned and the penetration J19 leakage continued to

diminish over the next several days. The last leakage was recorded on April 25, 2015 from the penetration J19 at a rate of approximately 1 drop per minute. It is likely that the leakage observed April 22 through 25, 2015 was residual leakage. Note that the cavity remained flooded through April 30, 2015. The chart below represents a comparison of the RF19 leakage to that of the RF18 leakage where the X-axis represents days following flood up and the Y-axis represents cumulative gallons leaked.



Note that the time from flood up to first observation of leakage during RF19 was four days versus two days during RF18. In addition, the leakage during RF19 lasted only five days versus fourteen days during RF18. The RF19 total leakage was less than 25% of that collected during RF18. The characteristic deltas between the observed leakage from RF18 to RF19 will be taken into consideration when developing leak investigation efforts for RF20.

From the monitoring conducted during RF19 it can be concluded that the source of the leakage has not degraded from RF18 to RF19. No leakage was observed from any other air gap penetration sleeves and there was no sign of leakage from the end of the other three drywell air gap drains (at 80, 160 and 340 degree azimuths) or from the excavated tunnels at 290, 155 and 115 degree azimuths. The Reactor Cavity to Drywell Seal Rupture Drain Alarm (HC.OP-AR.ZZ-0024, Alarm point D3837) did not actuate. All leakage stopped well before draining of the reactor cavity.

B. UT Measurements (License Condition 2.C. (27) c.)

The UT measurements prescribed by license condition 2.C. (27) c. were performed during RF19. Based on the consistency of the UT measurements with those taken in previous outages, PSEG has concluded that no corrosion is occurring on the drywell shell.

UT measurements were performed on the drywell shell at the 225 degree azimuth between 86’-11” and 93’-0” elevation (below the J13 penetration group). The lowest UT measurements occurred on a plate below the J13 penetration group and measured 1.475" in RF16, 1.470” in RF17, 1.477” in RF18, and.1.490” in RF19. Note that these readings were not at the same measurement point but were the lowest of all recorded readings taken during the respective outages. Comparing the lowest reading of 1.470” (from RF17) to the analysis limit of 1.4375” proves that at least 32.5 mils thickness margin remains. Further, the consistency of the thickness measurements proves that no corrosion to the drywell shell is occurring below the J13 penetration group. It should be noted that during development of the HCGS license renewal application, PSEG concluded that the cause of the lower readings on this plate were due to the plate’s construction tolerances being at the lower end, but acceptable for use. UT measurements were also performed for the full circumference of the drywell shell between elevations 86’-11” and 88’-0”. The bottom of the drywell air gap is on the outside of the drywell shell between these elevations. The lowest UT measurements at the bottom of the drywell were 1.480” in RF16, 1.477” in RF17, 1.471” in RF18, and 1.475” in RF19. Note that these readings were not at the same measurement point but were the lowest of all recorded readings taken during the respective outages. Comparing the lowest reading of 1.471” (from RF18) to the analysis limit of 1.4375” shows that 33.5 mils thickness margin remains. Based on the consistency of these UT measurements, PSEG has concluded that no corrosion is occurring in the drywell shell at the bottom of the drywell air gap.

Nevertheless, even if a very conservative corrosion rate of 6 mils per cycle were to be assumed, the analysis limit of 1.4375” would not be reached for at least 5 cycles. The UT measurements will be taken again during the RF20 outage to confirm that no corrosion is occurring in the drywell shell.

The UT measurement activities required to be completed during RF19 by license condition 2.C. (27) c. were completed as described above. License condition 2.C. (27) c requires these UT measurement activities for the three refueling outages following establishment of drainage capability from the bottom of the drywell air gap. RF19 is the second of these outages. Therefore, these UT measurement activities will be performed during the next outage. The results of the RF20 UT measurement activities will be compared to the previous UT measurement results to determine if any corrosion is occurring and to determine a corrosion rate if corrosion is identified. Should a significant corrosion rate be detected, the condition will be entered into the corrective action process for resolution.

Conclusion

The actions taken by PSEG during RF19 to satisfy license condition 2.C.(27)b. and 2.C.(27)c. were submitted by PSEG Letter No. LR-N15-0147 (Reference 46). This report satisfied the reporting requirements of 2.C.(27)c. The results of the UT measurements demonstrate there are currently no drywell surfaces requiring augmented inspections in accordance with IWE requirements.

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

HCGS Types B and C testing program requires testing of electrical penetrations, airlocks, hatches, flanges, and containment isolation valves in accordance with 10 CFR 50, Appendix J, Option B, and RG 1.163. 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 the HCGS TS 6.8.4.f, the allowable maximum pathway total Types B and C leakage is $0.6L_a$ (Note: For HCGS, $0.6L_a$ is defined as 79,800 sccm and L_a is defined as 133,000 sccm).

As discussed in NUREG-1493 (Reference 6), Type B and Type C tests can identify the vast majority of all potential containment leakage paths. Type B and Type C testing will continue to provide a high degree of assurance that containment integrity is maintained.

A review of the HCGS Type B and Type C test results from 2009 through 2015 has shown significant margin between the actual As-Found (AF) and As-Left (AL) outage summations and the regulatory requirements. A review of these years As-Found/As-Left test values can be summarized as:

- HCGS As-Found minimum pathway leak rate shows an average of 39.6% of 0.6 L_a with a high of 56.7% of $0.6L_a$ or 0.34 of L_a.
- HCGS As-Left maximum pathway leak rate shows an average of 54.4% of 0.6 L_a with a high of 78.1% of 0.6 L_a or 0.47 of L_a.

Table 3.6.3-1 provides the LLRT data trend summary for HCGS since 2009 (last ILRT was 2009).

Table 3.6.3-1 HCGS Types B and C LLRT Combined As-Found/As-Left Trend Summary					
RFO & Year	**R15 2009**	**R16 2010**	**R17 2012**	**R18 2013**	**R19 2015**
AF Min Path (sccm)	21,628	30,226	45,217	26,348	34,795
Fraction of L_a [1]	0.16	0.23	0.34	0.20	0.26
AL Max Path (sccm)	48,208	35,690	41,281	62,319	29,634
Fraction of L_a	0.36	0.27	0.31	0.47	0.22
AL Min Path (sccm)	17,957	15,358	18,470	22,887	12,699
Fraction of L_a	0.14	0.12	0.14	0.17	0.10

(1) 0.6 L_a = 79800 sccm and L_a = 133,000 sccm

This summary shows that there has been no As-Found failure that resulted in exceeding the TS 6.8.4.f limit of 1.0 L_a and demonstrates a history of successful tests. The As-Found minimum pathway summations represent the high quality of maintenance of Type B and Type C tested components while the As-Left maximum pathway summations represent the effective management of the Containment Leakage Rate Testing Program.

Subsequent to the EPU increase in P_a to 50.6 psig, all Type B and Type C tested components have been tested at the increased EPU P_a of 50.6 psig.

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

Table 3.6.4-1 identifies HCGS components that were on Appendix J, Option B performance-based extended test intervals, but have not demonstrated acceptable As-Found performance during the previous two outages. The component test interval shown has been reduced to 30 months.

Table 3.6.4-1 HCGS Type B and C LLRT Program Implementation Review As-Found Failures of Components on Extended Intervals						
2015 – Operating Cycle 19 and RF19						
Component	**As-found sccm**	**Admin Limit Alert / Actions ccm**	**As-left sccm**	**Cause of Failure**	**Corrective Action**	**Scheduled Interval**
None						
2013 – Operating Cycle 18 and RF18						
Globe Valve 1BCHV-F027A RHR Loop A SP Spray	Gross (Min Path 0, Closed system boundary outside Drywell)	247/349	18	Seat Warping	In body repair, Retest SAT. Evaluation 80110417-0050	30 month
1GSHV-5031 Type B Packing	234	129.4	234	New packing not sufficiently compressed	Order 60117175 completed.	30 month
1FDPSV-F077 Type B Flange	400	47	400	Leakage of 400 sccm was accepted per evaluation 80110417-0010 pending on-line corrective maintenance.	Corrective Maintenance Order 60113313 was initiated and scheduled for the RCIC outage window. Gaskets replaced. Work completed.	30 months

Test Frequency Results for Type B Components on Extended Frequencies

- All 44 electrical penetration assemblies are on a 10-year test frequency with each penetration being tested once over a 10-year period.

- All 64 mechanical bellows are on a 2R frequency such that each assembly is tested once every other outage with the exception of P1C Inboard (249 sccm), P38A Outboard (100 sccm) and P229C Inboard (84 sccm), which are tested each RFO. All mechanical bellows were tested in RF19. No changes to test frequencies were performed following RF19.

- There are 50 Type B tested penetrations other than those listed above which are eligible for extended interval testing. Of the 50, 48 or 96% of the Type B tested components are on extended intervals.

Test Frequency Results for Type C Components on Extended Frequencies

- There are 100 Type C tested components eligible for extended interval testing. Of the 100, 94 or 94% of the Type C tested components are on extended intervals.

3.6.5 Operating Experience

During the conduct of the various examinations and tests conducted in support of the containment related programs previously mentioned, issues that do not meet established criteria or that provide indication of degradation, are identified, placed into the site's corrective action program, and corrective actions are planned and performed.
For the HCGS Primary Containment, the following industry events have been evaluated for impact:

- Generic Letter (GL) 98-04, "Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss-of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment"
- IN 2006-01, "Torus Cracking at Fitzpatrick Nuclear Power Plant"
- IN 2010-12, "Containment Liner Corrosion"
- Regulatory Issue Summary (RIS) 2016-07, "Containment Shell Or Liner Moisture Barrier Inspection"

Each of these areas is discussed in detail in Sections 3.6.5.1 through 3.6.5.4, respectively.

3.6.5.1 GL 98-04 (Reference 52)

On July 14, 1998, the NRC issued the referenced GL addressing issues which have generic implications regarding the impact of potential coating debris on the operation of SSCs during a postulated design basis LOCA. Protective coatings are necessary inside containment to control radioactive contamination and to protect surfaces from erosion and corrosion. The GL requests

information under 10 CFR 50.54(f) to evaluate the addressees' programs for ensuring that Service Level 1 protective coatings inside containment do not detach from their substrate during a design basis LOCA and interfere with the operation of the emergency core cooling system (ECCS) and the safety related containment spray system (CSS). The NRC intends to use this information to assess whether current regulatory requirements are being correctly implemented and whether these requirements need to be revised.

PSEG Response:

PSEG has implemented controls for the procurement, application, and maintenance of Service Level 1 protective coatings used inside the containment in a manner that is consistent with the licensing basis and regulatory requirements applicable to HCGS. The requirements of 10 CFR 50 Appendix B are implemented through specification of appropriate technical and quality requirements for the Service Level 1 coatings program which includes ongoing maintenance activities.

For HCGS, Service Level 1 (Note 1) coatings are subject to the requirements of ANSI N101.2, Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities as described in the HCGS Updated Final Safety Analysis Report (UFSAR) Section 6.1.2.2. HCGS complies with the requirements of ANSI N101.4-1972, Quality Assurance for Protective Coatings Applied to Nuclear Facilities, as endorsed and modified by Regulatory Guide 1.54. Service Level 1 coatings are subject to the requirements of PSEG's technical standard for primary containment coatings.

> Note 1: This response applies to Service Level I coatings used in primary containment that are procured, applied and maintained by PSEG or its contractor. It does not address the relatively small amount of coatings applied by vendors on supplied equipment and miscellaneous structural supports.

The Service Level 1 designation is applied to coatings in five areas:

- the drywell;
- the suppression chamber (torus)
- structural steel and gallery steel;
- concrete surfaces inside the drywell; and
- exposed uninsulated carbon steel surfaces of mechanical equipment, piping, electrical equipment and auxiliaries.

Adequate assurance that the applicable requirements for the procurement, application, inspection, and maintenance are implemented is provided by procedures and programmatic controls, approved under the PSEG Quality Assurance program.

(a) Materials used for new applications or repair of Service Level 1 coatings are procured in accordance with PSEG's technical standard for HCGS primary containment coatings from vendors with quality assurance programs meeting the applicable requirements of 10 CFR 50 Appendix B. The applicable technical and quality requirements, which the vendor is required to meet, are specified by PSEG in procurement documents. Acceptance activities are conducted in

accordance with procedures, which are consistent with ANSI N 45.2 requirements (e.g., receipt inspection, source surveillance, etc.). This specification of required technical and quality requirements combined with appropriate acceptance activities provides adequate assurance that the coatings received meet the requirements of the procurement documents.

(b) The qualification testing of Service Level 1 coatings used for new applications or repair/replacement activities inside containment meets the applicable requirements contained in the standards and regulatory commitments referenced above. These coatings, including any substitute coatings, have been evaluated to meet the applicable standards and regulatory requirements previously referenced. PSEG's technical standard for HCGS primary containment coatings requires documentation that coating materials meet the applicable standards referenced in ASTM D 3842, Standard Guide for Selection of Testing Coatings Used in Light Water Nuclear Power Plants. For coating touch-up operations (remedial work on coating defects where the defect is less than one square foot in area), the coating materials are required to be the same as those originally applied, unless otherwise specified.

(c) The surface preparation, application and surveillance during installation of Service Level 1 coatings used for new applications or repair/replacement activities inside containment meet the applicable portions of the standards and regulatory commitments referenced above. The requirements for application (including surface preparation), touchup, repair, inspection and testing of Service Level 1 protective coatings are contained in the PSEG technical standard for HCGS primary containment coatings. Documentation of completion of these activities is performed consistent with the applicable requirements. Where the requirements of the standards and regulatory commitments did not address or were not applicable to repair/replacement activities, these activities were performed in a manner consistent with the generally accepted practices for coatings repair/replacement. These practices are described in various ASTM standards and coating practice guidelines by industry organizations issued subsequent to those to which PSEG has a regulatory commitment. PSEG recognizes that the NRC has not formally endorsed many of the more recent ASTM standards or industry guidelines, but nonetheless, they provide useful information, which can be appropriately applied to provide assurance that repair/replacement activities on Service Level 1 coatings are effective in maintaining the acceptability of the coatings.

Inspections and tests during surface preparation and coating application are performed in accordance with PSEG's technical standard for HCGS primary containment coatings. Deviations from technical requirements identified during surface preparation or coating application are documented, evaluated and corrected in accordance with the technical standard. Coating non-conformances and degraded conditions observed during plant shutdowns when the containment is accessible are required to be documented and evaluated in accordance with PSEG's corrective action program. Documentation, evaluation and the resulting repair/replacement activities assure that the amount of Service Level 1 coatings which may be susceptible to detachment from the substrate during a LOCA event is minimized.

PSEG currently plans to perform an examination of the HCGS containment during the next RFO in accordance with Subsection IWE, "Requirements for Class MC and Metallic Liners of Class CC Components of Light-Water Cooled Power Plants," of Section XI of the ASME Code (1992 edition with 1992 addenda). During this examination, the overall condition of HCGS containment

coatings will be observed and visible non-conformances and degraded conditions will be documented and evaluated in accordance with PSEG's corrective action program. The next RFO (at this time) was scheduled to begin in February 1999.

Required Information:

Hope Creek does not have licensing-basis requirements for tracking the amount of unqualified coatings inside the containment and for assessing the impact of potential coating debris on the operation of safety-related SSCs during a postulated design basis LOCA.

In response to NRC Bulletin 96-03, PSEG is installing large passive replacement ECCS strainers at HCGS. One replacement strainer was installed on the "D" RHR pump suction during the RFO completed in December 1997. The remaining strainers will be installed during the RFO beginning in February 1999. Consequently, the following discussion addresses the anticipated licensing basis pending resolution of NRC Bulletin 96-03.

The design input to the ECCS strainer calculations for the amount of unqualified coatings, qualified coatings in steam/water jet zone of influence, and degraded qualified coatings in the containment (as identified from periodic visual inspections) is documented in the new ECCS strainer hydraulic calculations. Consequently the amount of these coating materials must be managed, in addition to the quantity of fibrous, particulate, and other miscellaneous debris, to assure that the analyzed functional capability of the ECCS is not compromised.

The new ECCS pump suction strainers have been designed to perform satisfactorily in the presence of 100% of the containment coatings which are installed in the LOCA pipe break steam/water jet zone of influence. This amount of coating debris is determined in accordance with the methodology documented in the BWR Owners' Group Utility Resolution Guidance (URG) document (NED0-32686), Section 3.2.2.2.2.1.1. The conservative methodology used to establish the amount of coating debris has been accepted by the NRC, as documented in the Safety Evaluation Report (SER) on the URG dated August 20, 1998.

An additional amount of coating debris is added to the debris from the zone of influence. This amount accounts for potential debris, which may result from coatings which are unqualified and/or degraded. Results of BWR Owners' Group LOCA testing of coupons representing unqualified coating systems provide compelling evidence that failure of typical unqualified coating systems, which pass a visual inspection, is highly unlikely in the first 30 minutes of the LOCA. Only for the first 2 to 15 minutes of the LOCA event, depending upon the pipe break size, are suppression pool turbulence levels adequate to maintain coating debris in suspension in the pool where it would be available for accumulation on the ECCS strainers. Since the coating debris will quickly settle to the bottom of the suppression pool after the turbulence subsides, none of the coating debris (if eventually released sometime after the first 30 minutes of the LOCA) would be available to accumulate on the strainers. In sizing the replacement ECCS strainers for Hope Creek, no credit was taken for the delayed release of coating debris; therefore, these designs are conservative with respect to the limit on this coating debris source. PSEG is participating in the BWR Owners' Group Containment Coatings Committee, and activities in progress are expected to result in an increase in the quantity of containment coating debris that can be accommodated on the strainers without challenging their functional capability.

3.6.5.2 Information Notice 2006-01 (Reference 54)

On January 12, 2006, the NRC issued IN 2006-01 to inform the owners of BWR Mark I containments about the occurrence and potential causes of the through-wall cracking of a torus in a BWR Mark I containment. This was in response to Torus cracking concerns found at Fitzpatrick Power Plant.

PSEG Response:

PSEG's HCGS conducted a walk down of the exterior Torus surfaces. ISI, Operations and Engineering conducted the walk down. No instances of leakage were identified.

During RF12 (December 2004) major cleaning and visual examinations of the Torus internal and external surfaces were performed in accordance with ASME XI - IWE requirements. ASME Section XI - IWE contains special requirements for examination of the Torus Vessel, a Metallic Primary Containment (Class MC), and requires visual examination once per period.

Further review and comparison of Fitzpatrick's and the design of the HCGS Torus and the high pressure coolant injection (HPCI) discharge design demonstrated a difference in the discharge failure mechanism to the Torus weld area. The Sparger will spread the temperature and pressure of the HPCI line dump area in the weld area thus dissipating the heat and reducing the possibility of stress to HCGS Torus.

Continued IWE Visual examination of the internal and external Torus under the ISI Long Term Plan is deemed acceptable to identify and address any issues as described in IN 2006-01.

3.6.5.3 Information Notice 2010-12 (Reference 53)

On September 23, 2010, the NRC issued Information Notice IN 2010-12 "Containment Liner Corrosion" which references examples of containment liner corrosion discovered at Beaver Valley, Brunswick and Salem.

PSEG Response:

HCGS is a BWR, and has a drywell shell as opposed to a containment liner. Unlike a containment liner, the drywell shell is a load carrying structure and provides a containment for the inert atmosphere in the drywell. As such, it is designed to be much more structurally substantial. The thickness of the drywell shell as compared to a liner makes it less vulnerable to corrosion problems. However, corrosion is still a concern, and must be monitored and mitigated.

The UT examinations (ASME Sect. XI Subsection IWE) performed in RF16 showed that the shell thickness has not been reduced below its nominal minimum, and was not projected to fall below the nominal minimum before the next examination in RF17. UT measurements were also performed by PSEG for the full circumference of the drywell shell between elevations 86'-11"

and 88'-0". The lowest UT measurements at the bottom of the drywell were 1.480" in RF16, 1.477" in RF17, 1.471" in RF18, and 1.475" in RF19. Comparing the lowest reading of 1.471" from RFO 18 to the analysis limit of 1.4375" shows that approximately 33.5 mils thickness margin remains. If a corrosion rate of 6 mils per cycle were to be assumed, the analysis limit of 1.4375" would not be reached for at least five cycles. The UT measurements will be taken again during the RFO 20 to confirm that no corrosion is occurring in the drywell shell.

A long term corrective action program is in place to monitor and mitigate corrosion of the drywell shell. The program performs periodic (during RF) UT examinations at specified locations to ensure the thickness does not reduce further than 10% below nominal minimum wall thickness. All testing and inspection associated with the program is in compliance with ASME Section XI Subsection IWE, Inservice Inspection of Nuclear Power Plant Components. Long term corrective action (LTCA) has been put in place to reanalyze the corrosion rate based on readings from RFOs, etc., to ensure the corrosion stays within permissible rates.

3.6.5.4 RIS 2016-07 (Reference 51)

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 that “Examination shall include moisture barrier materials intended to prevent intrusion of moisture against inaccessible areas of the pressure retaining metal containment shell or liner at concrete-to-metal interfaces and at metal-to-metal interfaces which are not seal-welded. Containment moisture barrier materials include caulking, flashing, and other sealants used for this application.” Examples of inadequate inspections have included licensees not identifying sealant materials at metal-to-metal interfaces as moisture barriers because they do not specifically match Figure IWE-2500-1, and licensees not inspecting installed moisture barrier materials, as required by Item E1.30, because the material was not included in the original design or was not identified as a “moisture barrier” in design documents.

PSEG Response:

As part of License Renewal, Hope Creek installed a caulk moisture barrier to the full perimeter of the drywell shell at the junction of the concrete floor slab at 86’-11”. The installation of the barrier was completed in RF18.

The inspection of the new installed Gap seal was added to the Containment ISI program as a Category E-A Item E1.11 class MC VT-G. The inspection is to be once every period per IWE examination requirements and License Renewal commitments.

3.6.6 License Renewal Aging Management

UFSAR Appendix A, “License Renewal Final Safety Analysis Report Supplement,” contains the UFSAR Supplement as required by 10 CFR 54.21(d) for the HCGS License Renewal Application (LRA). The NRC issued NUREG-2102, “Safety Evaluation Report Related to the License Renewal of Hope Creek Generating Station” (Reference 19) for the HCGS LRA.

The aging management activity descriptions presented in the UFSAR, Appendix A represent commitments for managing aging of the in-scope SSCs during the period of extended operation.

As part of the license renewal effort, it had to be demonstrated that the aging effects applicable for the components and structures within the scope of license renewal would be adequately managed during the period of extended operation. Hope Creek begins the period of extended operation on April 11, 2026.

In many cases, existing activities were found to be adequate for managing aging effects during the period of extended operation. In some cases, aging management reviews revealed that existing activities required enhancement to adequately manage applicable aging effects. In a few cases, new activities were developed to provide added assurance that aging effects are adequately managed.

The following programs/activities are credited with the aging management of the Primary Containment (Drywell and Torus).

- <u>10 CFR Part 50, Appendix J (UFSAR Appendix A.2.1.30</u>)

  The 10 CFR Part 50, Appendix J aging management program is an existing program that monitors leakage rates through the containment pressure boundary, including penetrations, fittings and other access openings, in order to detect age related degradation of the containment pressure boundary. Corrective actions are taken if leakage rates exceed acceptance criteria. The Primary Containment Leakage Rate Testing Program provides for aging management of pressure boundary degradation due to aging effects from the loss of leakage tightness, loss of sealing, loss of material, cracking, or loss of preload in various systems penetrating containment. The 10 CFR Part 50, Appendix J program also detects age related degradation in material properties of gaskets, o-rings and packing materials for the containment pressure boundary access points. Consistent with the current licensing basis, the containment leakage rate tests are performed in accordance with the regulations and guidance provided in 10 CFR Part 50, Appendix J, Option B, Regulatory Guide 1.163, “Performance-Based Containment Leak-Testing Program,” NEI 94-01 “Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50 Appendix J,” and ANSI/ANS 56.8, “Containment System Leakage Testing Requirements.”

- <u>ASME Section XI, Subsection IWE (UFSAR Appendix A.2.1.28)</u>

  The ASME Section XI, Subsection IWE aging management program is an existing program based on ASME Code and complies with the provisions of 10 CFR 50.55a. The program consists of periodic inspection of the primary containment surfaces and components, including its integral attachments, penetration sleeves, pressure retaining bolting, personnel airlock and equipment hatches, and other pressure retaining components for loss of material, loss of preload, and fretting or lockup.

  Examination methods include visual and volumetric testing as required by ASME Section

XI, Subsection IWE. Observed conditions that have the potential for impacting an intended function are evaluated for acceptability in accordance with ASME requirements or corrected in accordance with corrective action process.

The program will be enhanced to include (the current status is given in *Italics*):

1. Install an internal moisture barrier at the junction of the drywell concrete floor and the steel drywell shell prior to the period of extended operation.

    In RF18, HCGS installed the moisture barrier at the junction between the carbon steel drywell shell and the concrete floor slab at elevation 86' 11".

2. Revise the Hope Creek ASME Section XI, Subsection IWE implementing documents to require inspection of the moisture barrier for loss of sealing in accordance with IWE-2500, after it is installed. The original design for Hope Creek did not require an internal moisture barrier at the junction of the drywell concrete floor and steel drywell shell.

    The HCGS CISI Program Plan was updated on July 25, 2016. This update incorporated Table IWE-2500-1, Examination Category E-A, Item No. E1.30, Moisture Barriers.

3. Verify that the reactor cavity seal rupture drain lines are clear from blockage and that the monitoring instrumentation is functioning properly once prior to the period of extended operation, and one additional time during the first 10 years of the period of extended operation.

    DCP 80101462 installed a ball valve and test connection to the drain system such that water or air can be added to verify the drain lines alarm system is working properly and confirm that the drains are not obstructed. The test result confirmed that the alarm was received when water was added during the water test. The reactor cavity seal rupture drain lines were verified to be clear from blockage by the air test.

    The action to be completed during the first 10 years of the period of extended operation is being tracked by the corrective action program.

4. Establish drainage capability from the bottom of the drywell air gap on or before June 30, 2015. The drywell air gap will be divided into four approximately equal quadrants. Drainage consists of one drain in each quadrant for a total of four drains. Each drain will be open at the bottom of the drywell air gap and be capable of draining water from the air gap.

    Verify that drains at the bottom of the drywell air gap are clear from blockage once prior to the period of extended operation, and one additional time during the first 10 years of the period of extended operation.

Activities performed prior to and during the RF17 HCGS refueling outage have confirmed that there are four functional drains from the air gap.

In February, 2012, three drain pipes were boroscopically examined to confirm that they are clear and able to port any leakage into the air gap away from the drywell shell. These drain lines are located at azimuths 80, 160 and 340 degrees.

During the RF17 refueling outage, the excavated tunnel at the 250 degree azimuth was inspected to confirm that the tunnel was sloped such that it would port any leakage into the air gap away from the drywell shell (a second excavated tunnel at azimuth 120 degrees was also inspected and confirmed that it was sloped to port any leakage into the air gap away from the drywell). The minor leakage described below that was experienced during the outage confirmed that any leakage would flow away from the drywell. Grout was added as necessary at both tunnels to ensure a continuous flow path for leakage.

As a result of these activities and the boroscopic examinations described below, the three drains and the tunnel at the 250 azimuth were declared functional drains to satisfy license condition 26. The tunnel at the 120 azimuth was also confirmed to be a functional drain. This satisfies the license condition to have functional drains in each of four approximately equal quadrants around the drywell air gap.

The boroscopic examinations of the bottom of the drywell air gap through the penetrations located at elevation 93' in four quadrants, 90 degrees apart, were performed by certified VT-1 inspectors in accordance with ASME Section XI, Subsection IWA-2300 requirements. The videos have been reviewed to confirm there was no water evident at the bottom of the air gap.

Boroscopic examinations were also performed from the excavated tunnels horizontally around the bottom of the air gap to confirm the configuration of the intersection of the drain piping with the air gap. Two of the three drain pipes were examined (see Technical Evaluation 80106392) to confirm that the drains were functional and would port any leakage away from the drywell shell.

The action to be completed during the first 10 years of the period of extended operation is being tracked by the corrective action program.

5. Investigate the source of any leakage detected by the reactor cavity seal rupture drain line instrumentation and assess its impact on the drywell shell.

Alarm procedures for Vessel / Drywell Seal Leakage have actions to 1) Initiate notification in the corrective action program to investigate the

source of any leakage detected by the reactor cavity seal rupture drain line instrumentation and assess its impact on the drywell shell and 2) Monitor the drains at the bottom of the drywell air gap for leakage daily in accordance with HCGS Surveillance Log. During the period of the stations Renewed Operating License, there has been no history of the reactor cavity seal rupture drain line leakage alarm sealing in and staying in.

6. After drainage has been established from the bottom of the air gap from all four drains, monitor the drains at the bottom of the drywell air gap daily for leakage in the event leakage is detected by the reactor cavity seal rupture drain line instrumentation.

    Inspe*ctions are performed daily when the Reactor Cavity is flooded in accordance with HCGS Surveillance Log.*

7. Monitor penetration sleeve J13 daily for water leakage when the reactor cavity is flooded up. In addition, perform a walkdown of the torus room to detect any leakage from other drywell penetrations. These actions shall continue until corrective actions are taken to prevent leakage through J13 or through the four air gap drains.

    Inspections are performed daily when the Reactor Cavity is flooded in accordance with HCGS Surveillance Log.

8. Until drainage is established from all four drains, when the reactor cavity is flooded up, perform boroscope examination of the bottom of the drywell air gap through penetrations located at elevation 93’ in four quadrants, 90 degrees apart. The personnel performing the boroscope examination shall be certified as VT-1 inspectors in accordance ASME Section XI, Subsection IWA-2300, requirements. The examiners will look for signs of water accumulation and drywell shell corrosion. Adverse conditions will be documented and addressed in the corrective action program.

    The boroscopic examinations of the bottom of the drywell air gap through the penetrations located at elevation 93' in four quadrants, 90 degrees apart, were performed by certified VT-1 inspectors in accordance with ASME Section XI, Subsection IWA-2300 requirements. The videos have been reviewed to confirm there was no water evident at the bottom of the air gap.

    Drainage has been established from all four drywell air gap drains. All the requirements to be performed until drainage is established from all four drains, when the reactor cavity was flooded up have been completed.

After drainage has been established from the bottom of the air gap from all four drains, monitor the lower drywell air gap drains daily for water leakage when the

reactor cavity is flooded up.

Inspections are performed daily when the Reactor Cavity is flooded in accordance with HCGS Surveillance Log.

9. Until drainage is established from all four drains, perform UT thickness measurements each refuel outage from inside the drywell in the area of the drywell shell below the J13 penetration sleeve area to determine if there is a significant corrosion rate occurring in this area due to periodic exposure to reactor cavity leakage. In addition, UT measurements shall be performed each refuel outage around the full 360 degree circumference of the drywell between elevations 86'-11" and 88'-0" (underside of the torus down comer vent piping penetrations). Inspection and acceptance criteria will be in accordance with IWE-2000 and IWE-3000 respectively. The results of the UT measurements shall be used to establish a corrosion rate and demonstrate that the effects of aging will be adequately managed such that the drywell can perform its intended function until April 11, 2046. Evidence of drywell shell degradation will be documented and addressed in the corrective action program.

After drainage has been established from the bottom of the air gap from all four drains, UT thickness measurements will be taken each of the next three refueling outages at the same locations as those previously examined as described above. These UT thickness measurements will be compared to the results of the previous UT inspections and, if corrosion is ongoing, a corrosion rate will be determined for the drywell shell. In the event a significant corrosion rate is detected, the condition will be entered in the corrective action process for evaluation and extent of condition determination.

PSEG performed the required UT measurements during RF19. Based on the UT measurements, PSEG concluded that no corrosion is occurring on the drywell shell.

UT measurements were performed by PSEG on the drywell shell at the 225 degree azimuth between 86'-11" and 93'-0" elevation (below the J 13 penetration group). The lowest UT measurements occurred on a plate below the J 13 penetration group and measured 1.475" in RF16, 1.470" in RF17, 1.477" in RF18, and 1.490" in RF19. Comparing the lowest reading of 1.470" from RF17 to the analysis limit of 1.4375" shows approximately 32.5 mils thickness margin remains.

UT measurements were also performed by PSEG for the full circumference of the drywell shell between elevations 86'-11" and 88'-0". The lowest UT measurements at the bottom of the drywell were 1.480" in RF16, 1.477" in RF17, 1.471" in RF18, and 1.475" in RF19. Comparing the lowest reading of 1.471" from RF18 to the analysis limit of 1.4375" shows that approximately 33.5 mils thickness margin remains. If a corrosion rate of 6 mils per cycle were to be assumed, the analysis limit of

1.4375" would not be reached for at least five cycles. The UT measurements will be taken again during the RF20 to confirm that no corrosion is occurring in the drywell shell.

UT measurement activities are required for three RFOs following establishment of drainage capability from the bottom of the drywell air gap. RF19 was the second of these outages. Therefore, PSEG will continue these UT measurement activities for the next RF (RF20). (Reference 49)

10. The cause of the reactor cavity water leakage will be investigated and repaired, if practical, before period of extended operation (PEO). If repairs cannot be made prior to the PEO, the program will be enhanced to incorporate the following aging management activities, as recommended in the Final Interim Staff Guidance LR-ISG-2006-01.

    a) Identify drywell surfaces requiring examination and implement augmented inspections for the period of extended operation in accordance with IWE-1240, as identified in Table IWE-2500-1, Examination Category E-C.

    The containment section of the ISI Classification Basis Document discusses the containment design and components. Metal containment surface areas subject to accelerated degradation and aging require augmented examination per Examination Category E-C and Paragraph IWE-1240.

    A significant condition is a condition that is identified as requiring application of additional augmented examination requirements under Paragraph IWE-1240.

    No significant conditions were identified in the First CISI Interval.

    Refer to Section 3.6.2, "Augmented Inspections," for the description of Conditions that are currently identified in the Second CISI Interval as requiring application of additional augmented examination requirements.

    b) Demonstrate through the use of augmented inspections that corrosion is not occurring or that corrosion is progressing so slowly that the age-related degradation will not jeopardize the intended function of the drywell shell through the period of extended operation. (License Condition 2.C.(27)c.)

    PSEG performed the required UT measurements during RF19. Based on the UT measurements, PSEG concluded that no corrosion is occurring on the drywell shell

Reference Item 9, above for UT measurement details.

UT measurement activities are required for three RFOs following establishment of drainage capability from the bottom of the drywell air gap. RF19 was the second of these outages. Therefore, PSEG will continue these UT measurement activities for the next RF (RF20). (Reference 49).

c) Develop a corrosion rate that can be inferred from past UT examinations. If degradation has occurred, evaluate the drywell shell using the developed corrosion rate to demonstrate that the drywell shell will have sufficient wall thickness to perform its intended function through the period of extended operation. (License Condition 2.C.(27)b.)

PSEG performed the required UT during RF19. Based on the UT measurements, PSEG concluded that no corrosion is occurring on the drywell shell.

Reference Item 9, above for UT measurement details.

UT measurement activities are required for three RFOs following establishment of drainage capability from the bottom of the drywell air gap. RF19 was the second of these outages. Therefore, PSEG will continue these UT measurement activities for the next RF (RF20). (Reference 49).

The PEO begins on April 11, 2026. The investigation is still in progress. A summary of the investigation is provided. The reactor cavity leakage into the drywell air gap region is currently very small and measured in drops per minute (total for 2 egress paths) and materializes when the reactor cavity is flooded. Hence, the reactor cavity leakage occurs generally 2-3 weeks every refueling cycle (eighteen months). UT measurements to date have demonstrated that this leakage has not resulted in any corrosion of the drywell shell. If the leakage is not repaired prior to the PEO, the IWE program will be enhanced to incorporate the License Renewal commitments within the schedule described above.

- <u>Protective Coating Monitoring and Maintenance Program (UFSAR Appendix A.2.1.34)</u>

The Protective Coating Monitoring and Maintenance Program is an existing program that provides for aging management of Service Level 1 coatings inside the drywell and torus. Service Level 1 coatings are used in areas where coating failure could adversely affect the operation of post-accident fluid systems and thereby impair safe shutdown. The Protective Coating Monitoring and Maintenance Program provides for inspections,

assessments, and repairs for any condition that adversely affects the ability of Service Level 1 coatings to function as intended.

3.6.7 Supplemental Inspection Requirements

With the implementation of the proposed change, TS 6.8.4.f 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 inspections performed by the Containment Inservice Inspection Program (IWE) and the Containment Coatings Inspection and Assessment Program, TS 3.6.1.5 requires the structural integrity of the primary containment to be maintained at a level consistent with the acceptance criteria in Specification 4.6.1.5.1. SR 4.6.1.5.1 requires the structural integrity of the exposed accessible interior and exterior surfaces of the primary containment to be determined in accordance with the Primary Containment Leakage Rate Testing Program.

The requirements of TS 3.6.1.5 and SR 4.6.1.5.1 remain unchanged by this submittal. For HCGS, no additional inspections are required.

3.6.8 NRC SER Limitations And Conditions

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

The NRC staff found that the use of NEI TR 94-01, Revision 2, was acceptable for referencing by licensees proposing to amend their TS to permanently extend the ILRT surveillance interval to 15 years, provided the following conditions as listed in Table 3.6.8.1-1 were satisfied:

Table 3.6.8.1-1, NEI 94-01 Revision 2-A Limitations and Conditions

Limitation/Condition (From Section 4.0 of SE)	HCGS 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.)	HCGS 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.

Table 3.6.8.1-1, NEI 94-01 Revision 2-A Limitations and Conditions	
Limitation/Condition **(From Section 4.0 of SE)**	**HCGS Response**
The licensee submits a schedule of containment inspections to be performed prior to and between Type A tests. (Refer to SE Section 3.1.1.3.)	Reference Section 3.6.2 (Table 3.6.2-1) 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 (Table 3.6.2-3) of this Submittal.
The licensee addresses any tests and inspections performed following major modifications to the containment structure, as applicable. (Refer to SE Section 3.1.4.)	There are no major modifications planned to the containment structure. Modifications to comply with NRC Order EA-13-109, as the result of the Fukushima Dai-ichi event are described in Section 3.2 of this Submittal.
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.)	HCGS 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, HCGS will also demonstrate to the NRC staff that an unforeseen emergent condition exists in the event an extension beyond the 15-year interval is required.
For plants licensed under 10 CFR Part 52, applications requesting a permanent extension of the ILRT surveillance interval to 15 years should be deferred until after the construction and testing of containments for that design have been completed and applicants have confirmed the applicability of NEI 94-01, Revision 2, and EPRI Report No. 1009325, Revision 2, including the use of past containment ILRT data.	Not applicable. HCGS was not licensed under 10 CFR Part 52.

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

The NRC staff found that the guidance in NEI TR 94-01, Revision 3, was acceptable for referencing by licensees in the implementation of the optional performance-based requirements of Option B to 10 CFR 50, Appendix J. However, the NRC staff identified two conditions on the use of NEI TR 94-01, Revision 3 (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 the following three (3) separate issues that are required to be addressed:

- Issue 1 – The allowance of an extended interval for Type C LLRTs of 75 months carries the requirement that a licensee's post-outage report include the margin between the Type B and Type C leakage rate summation and its regulatory limit.
- Issue 2 – In addition, a corrective action plan shall be developed to restore the margin to an acceptable level.
- Issue 3 – Use of the allowed 9-month extension for eligible Type C valves is only authorized for non-routine emergent conditions with exceptions as detailed in NEI 94-01, Revision 3-A, Section 10.1.

Response to Condition 1, Issue 1

The post-outage report shall include the margin between the Type B and Type C 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 Types B and C MNPLR total is greater than the HCGS leakage summation limit of 0.5 L_a, but less than the regulatory limit of 0.6 L_a, then an analysis and determination of a corrective action plan shall be prepared to restore the leakage summation margin to less than the HCGS leakage limit. The corrective action plan should focus on those components which have contributed the most to the increase in the leakage summation value and what manner of timely corrective action, as deemed appropriate, best focuses on the prevention of future component leakage performance issues so as to maintain an acceptable level of margin.

Response to Condition 1, Issue 3

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

Topical Report Condition 2

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

determination of the acceptability of the extension, demonstrating that the LLRT totals calculated represent the actual leakage potential of the penetrations.

Response to Condition 2

Condition 2 presents the following two (2) separate issues that are required to be addressed:

- Issue 1 - Extending the LLRT intervals beyond 5 years to a 75-month interval should be similarly conservative provided an estimate is made of the potential understatement and its acceptability determined as part of the trending specified in NEI 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 Types 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, HCGS will conservatively apply a potential leakage understatement adjustment factor of 1.25 to the actual As-Left leak rate for each Type C component currently on greater than a 60-month test interval up to the 75-month extended test interval. This will result in a combined conservative Type C total for all 75-month LLRTs being "carried forward" and will be included whenever the total leakage summation is required to be updated (either while on-line or following an outage).

When the potential leakage understatement adjusted leak rate total for those Type C components being tested on greater than a 60-month test interval up to the 75-month extended test interval is summed with the non-adjusted total of those Type C components being tested at less than or equal to a 60-month test interval, and the total of the Type B tested components, results in the MNPLR being greater than the HCGS leakage summation limit of 0.50 L_a, but less than the regulatory limit of 0.6 L_a, then an analysis and corrective action plan shall be prepared to restore the leakage summation value to less than the HCGS leakage limit. The corrective action plan should focus on those components which have contributed the most to the increase in the leakage summation value and what manner of timely corrective action, as deemed appropriate, best focuses on the prevention of future component leakage performance issues (Reference 44).

Response to Condition 2, Issue 2

If the potential leakage understatement adjusted leak rate MNPLR is less than the HCGS leakage summation limit of 0.50 L_a, then the acceptability of the greater than 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 Types 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 HCGS, in the event an adverse trend in the aforementioned potential leakage understatement adjusted Types 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 should 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 HCGS, an adverse trend is defined as three (3) consecutive increases in the final pre-mode change Types B and C MNPLR leakage summation values, as adjusted to include the estimate of applicable Type C leakage understatement, as expressed in terms of L_a.

3.7 Conclusion

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

Based on the previous ILRTs conducted at HCGS, 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 HCGS inspection programs:

- Containment Inservice Inspection Program (IWE)
- Containment Inspections per TS SR 4.6.1.5.1
- Containment Coatings Inspection and Assessment Program

This experience is supplemented by risk analysis studies, including the HCGS risk analysis provided in Attachment 3. The risk assessment concludes that increasing the ILRT interval on a permanent basis to a one-in-fifteen year frequency is not considered to be significant since it represents only a small change in the HCGS 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 11), provided a risk impact assessment for optimized ILRT intervals up to 15 years, utilizing current industry performance data and risk informed guidance. NEI 94-01, Revision 3-A, Section 9.2.3.1 (Reference 2), states that Type A ILRT intervals of up to 15 years are allowed by this guideline. The Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals, EPRI Report 1018243 (formerly TR-1009325, Revision 2-A), indicates that, in general, the risk impact associated with ILRT interval extensions for intervals up to 15 years is small. However, plant-specific confirmatory analyses are required.

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

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

For EPRI Report No. 1009325, Revision 2, 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 and RG 1.174.

The NRC staff, therefore, found that this guidance was acceptable for referencing by licensees proposing to amend their TS in regards to containment leakage rate testing, subject to the limitations and conditions noted in Section 4 of the SER.

The NRC staff reviewed NEI TR 94-01, Revision 3, and determined that it described an acceptable approach for implementing the performance-based requirements of Option B to 10 CFR 50, Appendix J, as modified by the limitations and conditions summarized in Section 4.0 of the associated SE. This guidance included provisions for extending Type C LLRT intervals up to 75 months. Type C testing ensures that individual CIVs are essentially leak tight. In addition, aggregate Type C leakage rates support the leakage tightness of primary containment by minimizing potential leakage paths.

The NRC staff, therefore, found that this guidance, as modified to include two limitations and conditions, was acceptable for referencing by licensees proposing to amend their TS in 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 limitations and conditions specified in NEI 94-01, Revision 2-A, dated October 2008, in a licensing action to satisfy the requirements of Option B to 10 CFR 50, Appendix J.

4.2 Precedent

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

- Surry Power Station, Units 1 and 2 (Reference 24)
- Donald C. Cook Nuclear Plant, Units 1 and 2 (Reference 25)
- Beaver Valley Power Station, Unit Nos. 1 and 2 (Reference 26)
- Calvert Cliffs Nuclear Power Plant, Unit Nos. 1 and 2 (Reference 27)
- Peach Bottom Atomic Power Station, Units 2 and 3 (Reference 28)
- Comanche Peak Nuclear Power Plant, Units 1 and 2 (Reference 39)

4.3 No Significant Hazards Consideration

This evaluation supports a request to amend Renewed Facility Operating License NPF-57 for Hope Creek Generating Station (HCGS). The proposed change would revise

the Operating License by amending Technical Specification (TS) Section 6.8.4.f, "Primary Containment Leakage Rate Testing Program" by replacing the reference to Regulatory Guide (RG) 1.163 (Reference 1) with a reference to Nuclear Energy Institute (NEI) Topical Report NEI 94-01, Revision 3-A, dated July 2012 (Reference 2) and the conditions and limitations specified in NEI 94-01, Revision 2-A, dated October 2008 (Reference 8), as the implementation documents used by HCGS to implement the performance-based leakage testing program in accordance with Option B of 10 CFR Part 50, Appendix J. The proposed change would also delete the listing of a one time exception previously granted to Integrated Leak Rate Test (ILRT) test frequency.

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

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

   Response: No.

   The proposed activity involves revision of the Hope Creek Generating Station (HCGS) Technical Specification (TS) 6.8.4.f, Primary Containment Leakage Rate Testing Program, to allow the extension of the HCGS Type A containment integrated leakage rate test interval to 15 years, and the extension of the Type C local leakage rate 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 existing 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 extension does 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 dose risk for changing the Type A Integrated Leak Rate Test (ILRT) interval from three-per-ten years to once-per-fifteen-years, measured as an increase to the total integrated dose risk for all internal events accident sequences, is 5.15E-03 person-rem/yr (0.01%) using the Electric Power Research Institute (EPRI) guidance with the base case corrosion included. This change meets both of the related acceptance criteria for change in population dose. The change in dose risk drops to 1.38E-03 person-rem/yr (<0.01%) when using the EPRI Expert Elicitation methodology. Therefore, this proposed extension does not involve a significant increase in the probability of an accident previously evaluated.

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 HCGS 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 American Society of Mechanical Engineers (ASME) Section XI, and TS requirements serve to provide a high degree of assurance that the containment would not degrade in a manner that is detectable only by a Type A test. Based on the above, the proposed test interval extensions do not significantly increase the consequences of an accident previously evaluated.

The proposed amendment also deletes an exception previously granted in amendment 147 to allow a one-time extension of the ILRT test frequency for HCGS. 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 HCGS is operated.

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

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

Response: No.

The proposed amendment to TS 6.8.4.f, "Primary Containment Leakage Rate Testing Program," involves the extension of the HCGS 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 an exception previously granted in amendment 147 to allow a one-time extension of the ILRT test frequency for HCGS. 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 HCGS is operated.

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

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

Response: No.

The proposed amendment to TS 6.8.4.f involves the extension of the HCGS 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 HCGS. 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 Types A, B, and C containment leakage tests specified in applicable codes and standards would continue to be met, with the acceptance of this proposed change, since these are not affected by changes to the Type A and Type C test intervals.

The proposed amendment also deletes an exception previously granted in amendment 147 to allow a one-time extension of the ILRT test frequency for HCGS. This exception was for an activity that has taken place; therefore, the deletion is solely an administrative action and does not change how HCGS 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, PSEG 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," dated September 1995

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

3. RG 1.174, Revision 2, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," dated May 2011

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

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

6. NUREG-1493, "Performance-Based Containment Leak-Test Program," dated January 1995

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

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

9. Letter from M. J. Maxin (NRC) to J. C. Butler (NEI), 'Final Safety Evaluation for Nuclear Energy Institute (NEI) Topical Report (TR) 94-01, Revision 2, "Industry Guideline for Implementing Performance-Based Option of 10 CFR 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)

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

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

12. PSEG Letter LR-N12-0212 to NRC Document Control Desk from J. F. Perry, "License Renewal Commitment Implementation," dated July 19, 2012 (ML12228A388)

13. Letter from D. H. Jaffe (NRC) to L. R. Eliason (PSEG), Issuance of Amendment 104 Related to the adoption of 10 CFR Part 50, Appendix J, Option B (TAC No. M98318), dated September 18, 1997 (ML011770097).

14. Letter from R. B. Ennis (NRC) to H. W. Keiser (PSEG), Issuance Of Amendment Re: Increase In Allowable Main Steam Isolation Valve (MSIV) Leakage Rate And Elimination Of MSIV Sealing System (TAC NO. MB1970) dated October 3, 2001 (ML0126600176).

15. Letter from G. F. Wunder (NRC) to R. A. Anderson (PSEG), Issuance Of Amendment Re: Containment Requirements During Fuel Handling And Removal Of Charcoal Filters (TAC NO. MB5548) dated April 15, 2003 (ML030760293).

16. Letter from G. F. Wunder (NRC) to R. A. Anderson (PSEG), Issuance Of Amendment Re: One-Time Extension Of Type A Integrated Leak Rate Test Interval (TAC NO. MB6551) dated April 16, 2003 (ML030660099).

17. Letter from J. G. Lamb (NRC) to W. Levis (PSEG), Issuance Of Amendment Re: Extended Power Uprate (TAC NO. MD3002) dated May 14, 2008 (ML081230581)

18. Hope Creek Generating Station Renewed Facility Operating License, Renewed License No. NPF-57, dated July 20, 2011 (ML11116A197).

19. NUREG-2102, Safety Evaluation Report Related to the License Renewal of Hope Creek Generating Station, Docket Number 50-354, dated June 2011 (ML11200A221).

20. ASTM D3911, “Standard Test Method for Evaluating Coatings Used in Light-Water Nuclear Power Plants at Simulated Design Basis Accident (DBA) Conditions”

21. Hope Creek Generating Station PRA Peer Review Report, BWROG Final Report, May 2009

22. HC-016 Self-Assessment of the Hope Creek PRA Against the Combined ASME/ANS PRA Standard Requirements Revision 1.

23. NEI 00-02, "Probabilistic Risk Assessment Peer Review Process Guidance," Rev. A3, dated March 2000.

24. 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, dated July 3, 2014 (ML14148A235)

25. Letter to L. Weber from A. Dietrich (NRC), “Donald C. Cook Nuclear Plant, Units 1 and 2 - Issuance of Amendments Re: Containment Leakage Rate Testing Program,” dated March 30, 2015 (ML15072A264)

26. Letter to E. Larson from T. 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,” dated April 8, 2015 (ML15078A058)

27. Letter to G. Gellrich from A. Chereskin (NRC), “Calvert Cliffs Nuclear Power Plant, Unit Nos. 1 and 2 - Issuance of Amendments Re: Extension of Containment Leakage Rate Testing Frequency,” dated July 16, 2015 (ML15154A661)

28. Letter to B. Hanson from R. 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)

29. American Society of Mechanical Engineers, Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications, ASME RA-S-2002, New York, New York, April 2002

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

31. HC-MSPI-001, MSPI BASIS DOCUMENT, Revision 7, March 29, 2012.

32. Letter from Mr. C. H. Cruse (Constellation Nuclear, Calvert Cliffs Nuclear Power Plant) to (NRC), “Response to Request for Additional Information Concerning the License Amendment Request for a One-Time Integrated Leakage Rate Test Extension,” dated March 27, 2002 (ML020920100)

33. Boiling Water Reactors Owners’ Group, BWROG PSA Peer Review Certification Implementation Guidelines, Revision 3, dated January 1997

34. ASTM D 714-02, “Standard Test Method for Evaluating Degree of Blistering of Paints”

35. ASTM D 610-07, “Standard Test Method for Evaluating Degree of Rusting on Painted Steel Surfaces”

36. SSPC-VIS 2, “Standard Test Method for Evaluating Degree of Rusting on Painted Steel Surfaces”

37. ASTM D 772, "Standard Test Method for Evaluating Degree of Flaking (Scaling) of Exterior Paints."

38. ASTM D 660, "Standard Test Method for Evaluating Degree of Checking of Exterior Paints."

39. Letter from B. Singal (NRC) to R. Flores (Luminant Generation Co.), “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)

40. ASTM D 661, "Standard Test Method for Evaluating Degree of Cracking of Exterior Paints."

41. ASTM D 610, " Standard Practice for Evaluating Degree of Rusting on Painted Steel Surfaces."

42. PSEG Letter LR-N14-0029 to NRC (Document Control Desk) from P. J. Davison, "License Renewal Commitment Implementation," dated February 7, 2014 (ML14038A014)

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

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

45. Letter from J. Hughey (NRC) to T. Joyce (PSEG), " Hope Creek Generating Station Completion of Review of the Implementation of License Renewal License Conditions 2.C.(27).b and 2.C.(27).c (TAC No. MF3537)," dated June 2, 2014 (ML14111A239)

46. PSEG Letter LR-N15-0147 to NRC (Document Control Desk) from P. J. Davison, “Hope Creek Generating Station License Renewal Commitment Implementation,” dated July 22, 2015 (ML15203A072)

47. PSEG Letter NLR-N87086 to NRC (Document Control Desk) from C. A. McNeill (PSEG), "Response To NRC Generic Letter 87-05, Hope Creek Generating Station, Docket No. 50-354," dated May 11, 1987

48. ERIN, Hope Creek Fire Probabilistic Risk Assessment Summary and Quantification Notebook, HC-PSA-104 Rev. 2, December 2015.

49. Letter from C. J. Parker (NRC) to R. Braun (PSEG), "Hope Creek Generating Station-Completion of Review of the Implementation of License Renewal License Conditions 2.C.(27)b and 2.C.(27)c (CAC No. MF6686)" dated February 11, 2016 (ML16027A194)

50. Letter from J. G. Lamb (NRC) to T. Joyce (PSEG), " Hope Creek Generating Station - Closeout of Review of the Implementation of License Renewal License Conditions (TAC No. ME9426)," dated May 13, 2013 (ML13114A965)

51. NRC Regulatory Issue Summary 2016-07, "Containment Shell Or Liner Moisture Barrier Inspection," dated May 9, 2016 (ML16068A436)

52. NRC Generic Letter No. 98-04, Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System after a Loss-of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment, dated July 14, 1998

53. NRC Information Notice 2010-12, "Containment Liner Corrosion," dated June 18, 2010 (ML100640449)

54. NRC Information Notice 2006-01, "Torus Cracking In A BWR Mark I Containment," dated January 12, 2006

Attachment 2

Mark-up of Proposed Technical Specification Pages

The following Technical Specifications pages for Renewed Facility Operating License NPF-57 are affected by this change request:

Technical Specification	Page
6.8.4.f, Primary Containment Leakage Rate Testing Program	6-16b

6.8.4.f Primary Containment Leakage Rate Testing Program

A program shall be established, implemented, and maintained to comply with the leakage rate testing of the containment as required by 10CFR50.54(o) and 10CFR50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in ~~Regulatory Guide 1.163, "Performance Based Containment Leak Test Program", dated September 1995, as modified by the following exception:~~

~~a. NEI 94-01-1995, Section 9.2.3: The first Type A test performed after April 12, 1994 shall be performed no later than April 12, 2009.~~

NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J," Revision 3-A, dated July 2012, and the conditions and limitations specified in NEI 94-01, Revision 2-A, dated October 2008.

The peak calculated containment internal pressure for the design basis loss of coolant accident, Pa, is 50.6 psig.

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

Leakage Rate Acceptance Criteria are:

a. Primary containment leakage rate acceptance criterion is less than or equal to 1.0 La. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are less than or equal to 0.6 La for Type B and Type C tests and less than or equal to 0.75 La for Type A tests;

b. Air lock testing acceptance criteria are:

1) Overall air lock leakage rate is less than or equal to 0.05 La when tested at greater than or equal to Pa,

2) Door seal leakage rate less than or equal to 5 scf per hour when the gap between the door seals is pressurized to greater than or equal to 10.0 psig.

The provisions of Specification 4.0.2 do not apply to the test frequencies specified in the Primary Containment Leakage Rate Testing Program.

The provisions of Specification 4.0.3 are applicable to the Primary Containment Leakage Rate Testing Program.

6.8.4.g. Radioactive Effluent Controls Program

A program shall be provided conforming with 10 CFR 50.36a for the control of radioactive effluents and for maintaining the doses to MEMBER(S) OF THE PUBLIC from radioactive effluents as low as reasonably achievable. The program (1) shall be contained in the ODCM, (2) shall be implemented by operating procedures, and (3) shall include remedial actions to be taken whenever the program limits are exceeded. The program shall include the following elements:

Attachment 3

Risk Assessment for the Type A Permanent Extension Request

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RISK ASSESSMENT FOR HCGS REGARDING THE ILRT (TYPE A) PERMANENT EXTENSION REQUEST

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Revision: 0

Project #: 1GWH32230.000
Project Name: HC-LAR-006
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RISK ASSESSMENT FOR HCGS REGARDING THE ILRT (TYPE A) PERMANENT EXTENSION REQUEST

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APPENDICIES

A PRA TECHNICAL ADEQUACY

1.0 OVERVIEW

The risk assessment associated with implementing a permanent extension of the Hope Creek Generating Station (HCGS) Integrated Leak Rate Test (ILRT) interval to 15 years is described in this document.

1.1 PURPOSE

The purpose of this analysis is to provide an assessment of the risk associated with implementing a permanent extension of the HCGS containment Type A ILRT interval from ten years to fifteen years. The risk assessment follows the guidelines from NEI 94-01 [1], the methodology outlined in Electric Power Research Institute (EPRI) TR-104285 [2], as updated by the EPRI Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals (EPRI TR-1018243) [3], the NRC regulatory guidance on the use of Probabilistic Risk Assessment (PRA) findings and risk insights in support of a request for a plant's licensing basis as outlined in Regulatory Guide (RG) 1.174 [4], and 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 [5]. The format of this document is consistent with the intent of the Risk Impact Assessment Template for evaluating extended integrated leak rate testing intervals provided in the EPRI TR-1018243 [3].

1.2 BACKGROUND

Revisions to 10CFR50, Appendix J (Option B) allow individual plants to extend the Integrated Leak Rate Test (ILRT) Type A surveillance testing requirements from three-in-ten years to at least once per 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 was less than the normal containment leakage of 1.0 L_a (allowable leakage).

The basis for a 10-year test interval is provided in Section 11.0 of NEI 94-01, Revision 0, and was established in 1995 during development of the performance-based Option B to Appendix J. Section 11.0 of NEI 94-01 states that NUREG-1493 [6], "Performance-Based Containment Leak Test Program," 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 EPRI TR-104285 [2].

The NRC report on performance-based leak testing, NUREG-1493 [6], 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 comparable BWR plant, that increasing the containment leak rate from the nominal 0.5 percent per day to 5 percent per day leads to a barely perceptible increase in total population exposure, and increasing the leak rate to 50 percent per day increases the total population exposure by less than 1 percent. Because ILRTs represent substantial resource expenditures, it is desirable to show that extending the ILRT interval will not lead to a substantial increase in risk from containment isolation failures to support a reduction in the test frequency for HCGS. The current analysis is being performed to confirm these conclusions based on HCGS specific PRA models and available data.

Earlier ILRT frequency extension submittals have used the EPRI TR-104285 [2] methodology to perform the risk assessment. In October 2008, EPRI 1018243 [3] was issued to develop a generic methodology for the risk impact assessment for ILRT interval extensions to 15 years using current performance data and risk informed guidance, primarily NRC Regulatory Guide 1.174 [4]. This more recent EPRI document considers the change in population dose, large early release frequency (LERF), and containment conditional failure probability (CCFP), whereas EPRI TR-104285 considered only the change in risk based on the change in population dose. This ILRT interval extension risk assessment for HCGS employs the EPRI 1018243 methodology,

with the affected System, Structure, or Component (SSC) being the primary containment boundary.

1.3 ACCEPTANCE CRITERIA

The acceptance guidelines in RG 1.174 [4] 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 1.0E-06 per reactor year and increases in large early release frequency (LERF) less than 1.0E-07 per reactor year. Note that a separate discussion in Section 5.8 of this risk assessment confirms that the CDF is negligibly impacted by the proposed ILRT interval change for HCGS. Therefore, since the Type A test has only a minimal impact on CDF for HCGS, the relevant criterion is the change in LERF. RG 1.174 also defines "small" changes in LERF as below 1.0E-06 per reactor year, provided that the total LERF from all contributors (including external events) can be reasonably shown to be less than 1.0E-05 per reactor year. RG 1.174 discusses defense-in-depth and encourages the use of risk analysis techniques to help ensure and show that key principles, such as the defense-in-depth philosophy, are met. Therefore, the increase in the conditional containment failure probability (CCFP) is also calculated to help show that an adequate defense-in-depth philosophy is maintained.

With regard to population dose, examinations of NUREG-1493 and Safety Evaluation Reports (SERs) for one-time interval extensions (summarized in Appendix G of [3]) indicate a range of incremental increases in population dose[(1)] that have been accepted by the NRC. The range of incremental population dose increases is from ≤0.01 to 0.2 person-rem/yr and 0.002 to 0.46% of the total accident dose. The total doses for the spectrum of all accidents (Figure 7-2 of NUREG-1493) result in health effects that are at least two orders of magnitude less than the NRC Safety Goal Risk. Given these perspectives, the NRC SER on this issue [7] defines a "small" increase in population

(1) The one-time extensions assumed a large leak (EPRI class 3b) magnitude of 35 L_a, whereas this analysis uses 100 L_a.

dose as an increase of ≤1.0 person-rem per year, or ≤1% of the total population dose (when compared against the baseline interval of 3 tests per 10 years), whichever is less restrictive for the risk impact assessment of the extended ILRT intervals. This definition has been adopted for the HCGS analysis.

The acceptance criteria are summarized below.

1. The estimated risk increase associated with permanently extending the ILRT surveillance interval to 15 years must be demonstrated to be “small.” (Note that Regulatory Guide 1.174 defines “very small” changes in risk as increases in CDF less than 1.0E-06 per reactor year and increases in LERF less than 1.0E-07 per reactor year. Since the type A ILRT test does not have a significant impact on CDF for HCGS, the relevant risk metric is the change in LERF. Regulatory Guide 1.174 also defines “small” risk increase as a change in LERF of less than 1.0E-06 reactor year.) Therefore, a small change in risk for this application is defined as a LERF increase of less than 1.0E-06.
2. Per the NRC SE, a small increase in population dose is also defined as an increase in population dose of less than or equal to either 1.0 person-rem per year or 1 percent of the total population dose, whichever is less restrictive.
3. In addition, the NRC SE notes that a small increase in Conditional Containment Failure Probability (CCFP) should be defined as a value marginally greater than that accepted in previous one-time 15-year ILRT extension requests (typically about 1% or less, with the largest increase being 1.2%). This would require that the increase in CCFP be less than or equal to 1.5 percentage points.

2.0 METHODOLOGY

A simplified bounding analysis approach consistent with the EPRI methodology [3] is used for evaluating the change in risk associated with increasing the test interval to fifteen years. The analysis uses results from a Level 2 analysis of core damage scenarios from the current HCGS PRA models of record [16, 17] and the subsequent containment responses to establish the various fission product release categories including the release size.

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 [3].
2. Develop plant-specific population dose rates (person-rem per reactor year) for each of the eight containment release scenario types from plant specific consequence analyses.
3. Evaluate the risk impact (i.e., the change in containment release scenario type frequency and population dose) of extending the ILRT interval to fifteen years.
4. Determine the change in risk in terms of Large Early Release Frequency (LERF) in accordance with RG 1.174 and compare this change with the acceptance guidelines of RG 1.174 [4].
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 and to variations in the fractional contributions of large isolation failures (due to liner breach) to LERF.

Furthermore,

- Consistent with the previous industry containment leak risk assessments, the HCGS assessment uses population dose as one of the risk measures. The other risk measures used in the HCGS assessment are the conditional containment failure probability (CCFP) for defense-in-depth considerations, and change in LERF to demonstrate that the acceptance guidelines from RG 1.174 are met.

- This evaluation for HCGS uses ground rules and methods to calculate changes in the above risk metrics that are consistent with those outlined in the current EPRI methodology [3].

3.0 GROUND RULES

The following ground rules are used in the analysis:

- The HCGS Level 1 and Level 2 internal events PRA models provide representative core damage frequency and release category frequency distributions to be utilized in this analysis. The technical adequacy of the PRA models is consistent with the requirements of Regulatory Guide 1.200 as relevant to this ILRT risk assessment. PRA adequacy is discussed in Appendix A.
- It is appropriate to use the HCGS internal events PRA 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 external events were to be included in the calculations; however, external events have been accounted for in the analysis based on the available information for HCGS.
- Dose results for the containment failures modeled in the PRA can be characterized by information provided in License Renewal Environmental Report for HCGS [8]. The Severe Accident Mitigation Alternatives (SAMA) analysis in the Environmental Report used a population estimated for the year 2046 and is judged reasonable for use in this ILRT evaluation. The current HCGS power level of 3,840 MWth as documented in the Updated Final Safety Analysis Report (UFSAR) [27] is lower than the power level used as input to the License Renewal Environmental Report L3 PSA as documented in Section F.3.5 of the Environmental Report. Therefore, no correction for power level is required.
- Accident classes describing radionuclide release end states and their definitions are consistent with the EPRI methodology [3] and are summarized in Section 4.2.
- The representative containment leakage for Class 1 sequences is 1 L_a. Class 3 accounts for increased leakage due to Type A inspection failures.
- The representative containment leakage for Class 3a is 10 L_a and for Class 3b sequences is 100 L_a, based on the recommendations in the latest EPRI report [3] and as recommended in the NRC SE on this topic [7]. It should be noted that this is more conservative than the earlier previous industry ILRT extension requests, which utilized 35 L_a for the Class 3b sequences.
- Based on the EPRI methodology and the NRC SE, the Class 3b sequences are categorized as LERF and the increase in Class 3b sequences is used as a surrogate for the ΔLERF metric.

- The impact on population doses from containment bypass scenarios is not altered by the proposed ILRT extension, but is accounted for in the EPRI methodology as a separate entry for comparison purposes. Since the containment bypass contribution to population dose is fixed, no changes on the conclusions from this analysis will result from this separate categorization.
- The reduction in ILRT frequency does not impact the reliability of containment isolation valves to close in response to a containment isolation signal.
- The use of the estimated 2046 population data is appropriate for this analysis. Precise evaluations of the projected population would not significantly impact the quantitative results, nor would it change the conclusions.
- An evaluation of the risk impact of the ILRT on shutdown risk is addressed using the generic results from EPRI TR-105189 [9].

4.0 INPUTS

This section summarizes the following:

- Section 4.1 - General resources available as input
- Section 4.2 - Plant specific resources required
- Section 4.3 - Impact of extension on detection of component failures that lead to leakage (small and large)
- Section 4.4 - Impact of extension on detection of steel liner corrosion that leads to leakage

4.1 GENERAL RESOURCES AVAILABLE

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

1. NUREG/CR-3539 [10]
2. NUREG/CR-4220 [11]
3. NUREG-1273 [12]
4. NUREG/CR-4330 [13]
5. EPRI TR-105189 [9]
6. NUREG-1493 [6]
7. EPRI TR-104285 [2]
8. Calvert Cliffs liner corrosion analysis [5]
9. EPRI 1018243 [3]
10. NRC Final Safety Evaluation [7]

The first study is applicable because it provides one basis for the threshold that could be used in the Level 2 PRA for the size of containment leakage that is considered significant and to be included in the model. The second study is applicable because it provides a basis of the probability for significant pre-existing containment leakage at the time of a core damage accident. The third study is applicable because it is a subsequent study to NUREG/CR-4220 that undertook a more extensive evaluation of the same database. The fourth study provides an assessment of the impact of different

containment leakage rates on plant risk. The fifth study provides an assessment of the impact on shutdown risk from ILRT test interval extension. The sixth study is the NRC's cost-benefit analysis of various alternative approaches regarding extending the test intervals and increasing the allowable leakage rates for containment integrated and local leak rate tests. The seventh study is an EPRI study of the impact of extending ILRT and LLRT test intervals on at-power public risk. The eighth study addresses the impact of age-related degradation of the containment liners on ILRT evaluations. EPRI 1018243 complements the previous EPRI report and provides the results of an expert elicitation process to determine the relationship between pre-existing containment leakage probability and magnitude. Finally, the NRC Safety Evaluation (SE) documents the acceptance by the NRC of the proposed methodology with a few exceptions. These exceptions (associated with the ILRT Type A tests) were addressed in the Revision 2-A of NEI 94-01 (and maintained in Revision 3-A of NEI 94-01) and the final version of the updated EPRI report [3], which was used for this application.

NUREG/CR-3539 [10]

Oak Ridge National Laboratory (ORNL) documented a study of the impact of containment leak rates on public risk in NUREG/CR-3539. This study uses information from WASH-1400 [14] as the basis for its risk sensitivity calculations. ORNL concluded that the impact of leakage rates on LWR accident risks is relatively small.

NUREG/CR-4220 [11]

NUREG/CR-4220 is a study performed by Pacific Northwest Laboratories for the NRC in 1985. The study reviewed over two thousand LERs, ILRT reports and other related records to calculate the unavailability of containment due to leakage. It assessed the "large" containment leak probability to be in the range of 1E-3 to 1E-2, with 5E-3 identified as the point estimate based on 4 events in 740 reactor years and conservatively assuming a one-year duration for each event.

NUREG-1273 [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 [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 [9]

The EPRI study TR-105189 is useful to the ILRT test interval extension risk assessment because this EPRI study provides insight regarding the impact of containment testing on shutdown risk. This study performed 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 result of the study concluded that a small but measurable safety benefit (shutdown CDF reduced by 1.0E-8/yr to 1.0E-7/yr) is realized from extending the test intervals from 3 per 10 years to 1 per 10 years.

NUREG-1493 [6]

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

- Reduction in ILRT frequency from 3 per 10 years to 1 per 20 years results in an "imperceptible" increase in risk.
- Given the insensitivity of risk to the containment leak rate and the small fraction of leak paths detected solely by Type A testing, increasing the interval between integrated leak rate tests is possible with minimal impact on public risk.

EPRI TR-104285 [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 Integrated Leak Rate Test (ILRT) and (Local Leak Rate Test) LLRT test intervals on at-power public risk. This study combined IPE Level 2 models with NUREG-1150 [15] Level 3 population dose models to perform the analysis. The study also used the approach of NUREG-1493 [6] in calculating the increase in pre-existing leakage probability due to extending the ILRT and LLRT test intervals.

EPRI TR-104285 used a simplified Containment Event Tree to subdivide representative core damage sequences into eight categories of containment response to a core damage accident:

1. Containment intact and isolated
2. Containment isolation failures due to support system or active failures
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 failure due to core damage accident phenomena
8. Containment bypass

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

> *"These study results show that 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..."*

Release Category Definitions

The EPRI methodology [2, 3] defines the accident classes that may be used in the ILRT extension evaluation. These containment failure classes, reproduced in Table 4.1-1, are used in this analysis to determine the risk impact of extending the Containment Type A test interval as described in Section 5 of this report.

TABLE 4.1-1

EPRI [2] / NEI CONTAINMENT FAILURE CLASSIFICATIONS

CLASS	DESCRIPTION
1	Containment remains intact including accident sequences that do not lead to containment failure in the long term. The release of fission products (and attendant consequences) is determined by the maximum allowable leakage rate values L_a, under Appendix J for that plant
2	Containment isolation failures (as reported in the 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.
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.

Calvert Cliffs Liner Corrosion Analysis [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. The HCGS containment is a pressure-suppression BWR/Mark I type with a steel shell in the drywell region, including a portion below the concrete drywell floor. The shell is surrounded by concrete.

EPRI 1018243 [3]

This report presents a risk impact assessment for extending ILRT surveillance intervals to 15 years. This risk impact assessment complements the earlier EPRI report, TR-104285 [2]. The earlier report considered changes to local leak rate testing intervals as well as changes to ILRT testing intervals. The original risk impact assessment [2] considers the change in risk based on population dose, whereas the revision [3] considers dose as well as large early release frequency (LERF) and conditional containment failure probability (CCFP). This report deals with changes to ILRT testing intervals and is intended to provide bases for supporting changes to industry and regulatory guidance on ILRT surveillance intervals.

The risk impact assessment using the Jeffrey's Non-Informative Prior statistical method is further supplemented with a sensitivity case using expert elicitation performed to address conservatisms. The expert elicitation is used to determine the relationship between pre-existing containment leakage probability and magnitude. The results of the expert elicitation process from this report are used as a separate sensitivity investigation for the HCGS analysis presented here in Section 6.2.

NRC Safety Evaluation Report [7]

This SE documents the NRC staff's evaluation and acceptance of NEI TR 94-01, Revision 2, and EPRI Report No. 1009325, Revision 2, subject to the limitations and conditions identified in the SE and summarized in Section 4.0 of the SE. These limitations (associated with the ILRT Type A tests) were addressed in the Revision 2-A of NEI 94-01 which are also included in Revision 3-A of NEI 94-01 [1] and the final version of the updated EPRI report [3]. Additionally, the SE clearly defined the acceptance criteria to be used in future Type A ILRT extension risk assessments as delineated previously in the end of Section 1.3.

4.2 PLANT-SPECIFIC INPUTS

The HCGS specific information used to perform this ILRT interval extension risk assessment includes the following:

- Level 1 and Level 2 PRA model quantification results [16, 17]
- Population dose within a 50-mile radius for various release categories [8]

HCGS Internal Events Core Damage Frequencies

The current HCGS Internal Events PRA model of record is based on an event tree / linked fault tree model that is characteristic of the as-built, as-operated plant. Based on the results reported in References [16, 17], the internal events Level 1 PRA core damage frequency (CDF) is 4.20E-06/yr. Table 4.2-1 provides the CDF results by accident class.

TABLE 4.2-1

HCGS CORE DAMAGE FREQUENCY BY ACCIDENT SEQUENCE SUBCLASS

ACCIDENT CLASS DESIGNATOR	SUBCLASS	DEFINITION	PRA MODEL RESULTS (PER RX YR)
Class I	A	Accident sequences involving loss of inventory makeup in which the reactor pressure remains high.	6.57E-07
	B	Accident sequences involving a station blackout and loss of coolant inventory makeup. (Class IBE is defined as "Early" Station Blackout events with core damage at less than 4 hours. Class IBL is defined as "Late" Station Blackout events with core damage at greater than 4 hours.)	IBE 1.19E-07 IBL 4.03E-07
	C	Accident sequences involving a loss of coolant inventory induced by an ATWS sequence with containment intact.	2.32E-08
	D	Accident sequences involving a loss of coolant inventory makeup in which reactor pressure has been successfully reduced to 200 psi.	7.98E-07
	E	Accident sequences involving loss of inventory makeup in which the reactor pressure remains high and DC power is unavailable.	2.52E-07
Class II	A	Accident sequences involving a loss of containment heat removal with the RPV initially intact; core damage; core damage induced post containment failure.	8.76E-07
	L	Accident sequences involving a loss of containment heat removal with the RPV breached but no initial core damage; core damage induced post containment failure. (Not used)	7.91E-10
	T	Accident sequences involving a loss of containment heat removal with the RPV initially intact; core damage; core damage induced prior to containment failure.	2.10E-11
	V	Classes IIA and III except that the vent operates as designed; loss of makeup occurs at some time following vent initiation. Suppression pool saturated but intact.	4.34E-08
Class III (LOCA)	A	Accident sequences leading to core damage conditions initiated by vessel rupture where the containment integrity is not breached in the initial time phase of the accident.	N/A
	B	Accident sequences initiated or resulting in small or medium LOCAs for which the reactor cannot be depressurized prior to core damage occurring.	6.64E-07
	C	Accident sequences initiated or resulting in medium or large LOCAs for which the reactor is a low pressure and no effective injection is available.	2.08E-08
	D	Accident sequences which are initiated by a LOCA or RPV failure and for which the vapor suppression system is inadequate, challenging the containment integrity with subsequent failure of makeup systems.	1.57E-08
Class IV (ATWS)	A	Accident sequences involving failure of adequate shutdown reactivity with the RPV initially intact; core damage induced post containment failure.	1.62E-07
	L	Accident sequences involving a failure of adequate shutdown reactivity with the RPV initially breached (e.g. LOCA or SORV); core damage induced post containment failure.	3.39E-09
Class V	---	Unisolated LOCA outside containment.	1.69E-07
		Total	4.21E-06[(1)]

Note to Table 4.2-1:

(1) The Level 1 based accident class CDF total of 4.21E-6/yr is slightly higher than the Level 1 based CDF total of 4.20E-06/yr from the single top model due to the generation of non-minimal cutsets. The difference is minimal and does not impact the results.

HCGS Internal Events Release Category Frequencies

The Level 2 Model that is used for HCGS was developed to calculate the LERF contribution as well as the other release categories evaluated in the model. Table 4.2-1 summarizes the pertinent HCGS results in terms of release category. The total Large Early Release Frequency (LERF) which corresponds to the H/E release category in Table 4.2-2 was found to be 8.45E-7/yr. The total release frequency is 3.00E-06/yr.

Table 4.2-2 provides release categories by accident class. Table 4.2.-3 provides release frequency contribution by accident class and by release category. Tables 4.2-2 and 4.2-3 results are from Table 3.4-4 of the PRA Summary Notebook [16]. Table 4.2-4 provides HCGS isolation failure sequence frequency contribution. The ILRT risk assessment methodology requires separate treatment of isolation failure sequences as these are addressed under EPRI Class 2. Information from Tables 4.2-2, 4.2-3 and 4.2-4 will be used in later sections for dose calculations.

TABLE 4.2-2

HCGS LEVEL 2 PRA MODEL RELEASE CATEGORIES AND FREQUENCIES[1]

CATEGORY	FREQUENCY/YR[2]
Intact	1.21E-06
H/E – High Early (LERF)	8.45E-07
M/E – Medium Early	4.58E-07
L/E – Low Early	7.39E-10
LL/E – Low Low Early	2.01E-07
H/I – High Intermediate	1.02E-06
M/I – Medium Intermediate	3.18E-07
L/I – Low Intermediate	2.83E-09
LL/I – Low Low Intermediate	1.37E-07
H/L – High Late	1.16E-12
M/L – Medium Late	0.00E+00
L/L – Low Late	3.19E-09
LL/L – Low Low Late	1.19E-08
Total Release Frequency (Excluding Intact Frequency)	3.00E-06
Core Damage Frequency[1]	4.21E-06

Notes to Table 4.2-2:

(1) The Level 2 based accident class CDF total of 4.21E-6/yr is slightly higher than the Level 1 based CDF total of 4.20E-06/yr from the single top model due to the generation of non-minimal cutsets. The difference is minimal and does not impact the results.

(2) Table 4.2-2 data source is Table 3.4-4 from the PRA Summary Notebook [16]. Table 3.4-4 of the PRA Summary Notebook is reproduced as Table 4.2-3 on the next page of this risk assessment (see next page).

TABLE 4.2-3

SUMMARY OF HCGS HC111A LEVEL 2 RELEASE CATEGORIES (/YR)(1) (2) (6)

CLASS	BASE CDF	INTACT(6)	LL/E	LL/I	LL/L	L/E	L/I	L/L	M/E	M/I	M/L	H/E	H/I	H/L	TOTAL RELEASE
IA/IE	9.09E-07	5.50E-07	1.67E-07	3.32E-08	1.19E-08	N/A	5.42E-10	1.18E-09	N/A	2.23E-08	0.00E+00	1.21E-07	2.00E-09	1.16E-12	3.59E-07
IBE	1.19E-07	6.86E-08	2.53E-08	7.27E-09	1.52E-12	5.65E-10	3.39E-11	1.36E-10	N/A	6.36E-10	0.00E+00	1.61E-08	5.89E-11	0.00E+00	5.01E-08
IBL	4.03E-07	1.80E-08	N/A	3.21E-08	0.00E+00	N/A	1.37E-09	0.00E+00	N/A	2.61E-07	0.00E+00	N/A	9.07E-08	0.00E+00	3.85E-07
IC	2.32E-08	2.29E-08	1.69E-11	0.00E+00	0.00E+00	1.74E-10	0.00E+00	0.00E+00	N/A	0.00E+00	0.00E+00	1.16E-10	0.00E+00	0.00E+00	3.06E-10
ID	7.98E-07	2.92E-07	9.12E-09	6.46E-08	0.00E+00	0.00E+00	8.87E-10	1.87E-09	N/A	3.30E-08	0.00E+00	3.94E-07	1.64E-09	0.00E+00	5.05E-07
II(3)	9.21E-07	0.00E+00	N/A	0.00E+00	N/A	N/A	0.00E+00	N/A	N/A	0.00E+00	N/A	N/A	9.21E-07	N/A	9.21E-07
IIIA	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
IIIB	6.64E-07	2.48E-07	N/A	0.00E+00	N/A	0.00E+00	0.00E+00	N/A	3.88E-07	7.54E-10	N/A	2.44E-08	3.72E-09	N/A	4.17E-07
IIIC	2.08E-08	7.86E-09	N/A	0.00E+00	N/A	0.00E+00	0.00E+00	N/A	6.57E-09	8.91E-12	N/A	1.66E-09	4.74E-09	N/A	1.30E-08
IIID(4)	1.57E-08	0.00E+00	N/A	N/A	N/A	0.00E+00	N/A	N/A	0.00E+00	N/A	N/A	1.57E-08	N/A	N/A	1.57E-08
IV(5)	1.65E-07	0.00E+00	0.00E+00	N/A	N/A	0.00E+00	N/A	N/A	6.32E-08	N/A	N/A	1.02E-07	N/A	N/A	1.65E-07
V	1.69E-07	0.00E+00	N/A	N/A	N/A	N/A	N/A	N/A	0.00E+00	N/A	N/A	1.69E-07	N/A	N/A	1.69E-07
Total	4.21E-06	1.21E-06	2.01E-07	1.37E-07	1.19E-08	7.39E-10	2.83E-09	3.19E-09	4.58E-07	3.18E-07	0.00E+00	8.45E-07	1.02E-06	1.16E-12	3.00E-06

Notes to Table 4.2-3:

(1) Level 2 quantified at a truncation value of 1E-12/yr.

(2) N/A indicates that the accident class did not contribute to release of that specific category.

(3) Due to success branch probability issues, the Class II end state frequency total was initially 9.50E-7/yr. The Class II end state totals were decreased proportionally by a factor of 0.97 (i.e., 9.21E-7/9.50E-7) to equal the total Class II Level 1 CDF of 9.21E-7/yr.

(4) Due to success branch probability issues, the Class IIID end state frequency total was initially 1.58E-8/yr. The Class IIID end state totals were decreased proportionally by a factor of 0.99 (i.e., 1.57E-8/1.58E-8) to equal the total Class IIID Level 1 CDF of 1.57E-8/yr.

(5) Due to success branch probability issues, the Class IV end state frequency total was initially 1.75E-7/yr. The non-H/E Class IV end state totals were decreased proportionally by a factor of 0.9 to equal the total Class IV Level 1 CDF of 1.65E-7/yr.

(6) The H/E (i.e., LERF) accident class results are based on PRAQuant file HC111A-LERF-CLASS.QNT (accident class level H/E results). Summing the results from the sequence level quantification may result in overestimating the results due to potential double-counting of cutsets.

TABLE 4.2-4

HCGS L2 ISOLATION FAILURE FREQUENCY CONTRIBUTION

HC111A L2 SEQUENCE	CDF CONTRIBUTION(1)(2)
IA1-43	4.49E-09
IBE-43	6.82E-09
IC1-43	3.42E-11
ID1-43	3.10E-07
3B-41	1.85E-09
3C-41	5.40E-11
Total Contribution	3.23E-07

Notes to Table 4.2-4:

(1) Source Table D.3-2, *Level 2 Sequence Quantification Results,* HCGS Level 2 PRA Analysis Notebook [34]. These sequences are all categorized as high early (H/E) releases.

(2) IBL1-043 is a containment isolation failure sequence that results in a high intermediate (H/I) release and is therefore not included in this table.

HCGS Population Dose Information

The population dose is calculated by using data provided in Appendix E of the Severe Accident Mitigation Alternatives (SAMA) of the HCGS License Renewal Report [8] and adjusting the results for the current HCGS model results and more recent population estimates. Each accident class was associated with an applicable Source Term from the SAMA evaluation. Table 4.2-5 reproduces the SAMA evaluation consequence categories ST1 through ST11 and the dominant release category for each consequence category.

The EPRI Class and SAMA Sequences are mapped in Table 4.2-6 to HCGS Release Frequencies found in Table 4.2-3. The frequencies found in the bottom row of Table 4.2-3 are brought forward to Table 4.2-6. Class 7 sequences are accident progression bins in which containment failure induced by severe accident phenomena occurs. Each Class 7 endstate (7a, 7b, 7c, 7d, 7e, 7f, 7g, 7h, or 7i) is mapped to a SAMA consequence category and each of the SAMA consequence releases. For example, EPRI Class 7f is mapped to SAMA consequence ST7 and its releases of M/I.

TABLE 4.2-5

ACCIDENT SEQUENCE CATEGORY DESCRIPTIONS FROM THE LICENSE RENEWAL SAMA EVALUATION[1]

SOURCE TERM	RELEASE CATEGORY	MAAP CASE	REPRESENTATIVE CASE DESCRIPTION	CSI RF[2]	TCD (HRS)[3]	TVF (HRS)[4]	TCF (HRS)[5]	TEND (HRS)[6]
ST1	H/E-HP	HC070500 IA-L2-NSPR	Loss of makeup at high pressure. No containment sprays.	0.57	0.60	3.0	3.2	38
ST2	H/E-LP	HC070504 ID-L2-NSPR	Loss of makeup at low pressure. No containment sprays.	0.15	0.47	4.7	4.8	38
ST3	H/E-BOC	HC070524 V-L2-17	Main steam line break outside containment. No injection. Release to environment begins at core damage.	0.69	0.13	6.8	6.9	38
ST4	H/I	HC070509 IIT-L2-WWW	Loss of containment heat removal and subsequent wetwell failure. RCIC and core spray provide injection. SRVs reclose at 50 psid. No containment sprays.	0.30	29.1	38.6	29.8	72
ST5	H/L	HC070515 IIA-L2-WWW	Loss of containment heat removal and subsequent wetwell failure. CRD, RCIC, and core spray provide injection. SRVs reclose at 50 psid. No containment sprays.	0.36	35.4	46.4	34.4	84
ST6	M/E	HC070519 IVA-L2-EDWWA	ATWS event with SLC failure and emergency depressurization. FW, HPCI, and LPCI provide injection until containment failure.	0.070	.77	5.4	0.58	38
ST7	M/I	HC070516 IIA-L2-DW	Loss of containment heat removal and subsequent drywell failure. CRD, RCIC, and core spray provide injection. SRVs reclose at 50 psid. No containment sprays.	0.057	35.4	46.5	34.4	84
ST8	M/L	HC070502 IA-L2-SPRYA	Loss of makeup at high pressure. Containment sprays fail at containment	0.040	0.58	3.0	21.8	38

TABLE 4.2-5

ACCIDENT SEQUENCE CATEGORY DESCRIPTIONS FROM THE LICENSE RENEWAL SAMA EVALUATION(1)

SOURCE TERM	RELEASE CATEGORY	MAAP CASE	REPRESENTATIVE CASE DESCRIPTION	CSI RF(2)	TCD (HRS)(3)	TVF (HRS)(4)	TCF (HRS)(5)	TEND (HRS)(6)
			failure.					
ST9	L/E, LL/E, L/I, LL/I	HC070503 IA-L2-SPRYB	Loss of makeup at high pressure. Containment sprays operate past containment failure.	2.3e-6	0.58	3.0	21.8	38
ST10	L/L, LL/L	HC070505 ID-L2-SPRY	Loss of makeup at low pressure. Containment sprays fail at containment failure.	9.8e-5	0.47	4.8	32.2	38
ST11	Intact	HC070525A OK-L2-A	Loss of makeup at high pressure. Containment sprays and suppression pool cooling operate. Intact containment with technical specification leakage.	1.7e-6	0.58	3.1	n/a	38

Notes to Table 4.2-5:

(1) This table is reproduced from Table E.3-5 in Appendix E of the HCGS Environmental Report

(2) CsI RF – Cesium iodine release fraction to environment

(3) Tcd – Time of core damage (maximum core temperature >1800°F

(4) Tvf – Time of vessel breach

(5) Tcf – Time of containment failure

(6) Tend – Time at end of run

TABLE 4.2-6

RELEASE CATEGORIES MAPPED TO EPRI CLASS, SAMA SEQUENCES AND HCGS HC111A RELEASE FREQUENCY

EPRI CLASS	SAMA TERM	RELEASE CATEGORY(1)	SAMA DOSE (PERSON-REM)	HC111A FREQ.(2) (/YR)
--	--	Base CDF	--	4.20E-06
1	ST11	Intact(4)	1.01E+03	1.21E-06
7a	ST1	H/E	1.82E+07	2.81E-07(3)
7a	ST2	H/E	1.38E+07	7.08E-08(3)
7b	ST4	H/I	8.75E+06	1.02E-06
7b	ST5	H/L	1.10E+07	1.16E-12
7c	ST6	M/E	1.31E+07	4.58E-07
7d	ST7	M/I	6.34E+06	3.18E-07
7d	ST8	M/L	6.38E+06	0.00E+00
7e	ST9	LL/E	6.44E+03	2.01E-07
7e	ST9	L/E	6.44E-+03	7.39E-10
7f	ST9	LL/I	6.44E+03	1.37E-07
7f	ST10	LL/L	6.87E+05	1.19E-08
7f	ST9	L/I	6.44E+03	2.83E-09
7f	ST10	L/L	6.87E+05	3.19E-09
8	ST3	H/E	2.34E+07	1.69E-07

Notes to Table 4.2-6:

(1) Release categories are consistent with release categories found in Table 4.2-4 and Table 4.2-3. These release categories are used to map dose (person-rem) from the SAMA evaluation to release categories frequencies from the 2011A Level 2 PRA model.

(2) Frequency is from Table 4.2.3 based on Release Category.

(3) Does not include frequency contribution from containment bypass (Class V) and H/E containment isolation failure sequences.

(4) The intact frequency determined as the difference between base CDF and total release frequencies (including Class V and isolation failure sequences).

Population Estimate

The HCGS SAMA dose results in Table 4.2-6 are based on a 50-mile population estimate developed from year 1990 and 2000 census data and projected to year 2046. The total 50-mile population used in the SAMA analysis was 6,634,468, as documented in Table E-3-2 *Estimated Population Distribution Within a 50-Mile Radius of HCGS, Year 2046* from Appendix E of the HCGS License Renewal Application.

Year 2010 census data is now readily available. As a reasonableness check, SecPop Version 4.2.0 [18] was used to calculate the 50-mile population around HCGS using both the year 2000 and 2010 census data files within SecPop, yielding 5,217,186 persons for year 2000 and 5,533,803 persons for year 2010. Thus, SecPop shows a population increase similar to the SAMA estimation for the 50-mile region surrounding HCGS between year 2000-2010. Based on this the similar population growth over that 10 year period, use of the SAMA projected value of 6,634,468 is judged reasonable.

Power Level and Containment Leak Rate

The parameters of reactor power level and containment leak rate that were used in the HCGS SAMA analysis were also compared with the current HCGS parameters and found to be appropriate to reflect the as-built, as-operate plant.

	POWER LEVEL	CONTAINMENT LEAK RATE
HCGS SAMA Analysis (2009)	3917 MWt(1)	0.5%/day(2)
HCGS 2016 ILRT Risk Assessment	3840 MWt(3)	0.5%/day(2)

Notes to Table:

(1) The 2009 SAMA Analysis used a Thermal power of 3917 MWt which is 2% higher the Extended Power Uprate (EPU) Thermal Power of 3840 MWt. This is noted in Section E.3.5 of the SAMA Analysis which states, “The core inventory corresponds to the end-of-cycle values for HCGS operating at 3917 MWt, 2 percent above the current (EPU) licensed value of 3,840 MWT.”

(2) Containment Leak Rate Limit is found in Section 6 of the HCGS Updated Final Safety Analysis Report [27].

(3) The Reactor Power Level is found in Section 1.1 of the HCGS Updated Final Safety Analysis Report [27].

Since the containment leak rate is unchanged from the SAMA evaluation and the SAMA power level used was conservatively higher than the current plant operating power level, no corrections are needed for these parameters. This approach provides a first-order approximation for HCGS of the population doses associated with each of the release categories from the SAMA evaluation. This is considered adequate since the conclusions from this analysis will not be substantially affected by the actual dose values that are used.

4.3 IMPACT OF EXTENSION ON DETECTION OF COMPONENT FAILURES THAT LEAD TO LEAKAGE (SMALL AND LARGE)

The ILRT can detect a number of component failures such as liner breach and failure of some sealing surfaces, which can lead to leakage. The proposed ILRT test interval extension may influence the conditional probability of detecting these types of failures. To ensure that this effect is properly accounted for, the EPRI Class 3 accident class as defined in Table 4.1-1 is divided into two sub-classes representing small and large leakage failures. These subclasses are defined as Class 3a and Class 3b, respectively.

The probability of the EPRI Class 3a failures may be determined, consistent with the latest EPRI guidance [3], as the mean failure probability estimated from the available data (i.e., 2 “small” failures that could only have been discovered by the ILRT in 217 tests leads to a 2/217=0.0092 mean value). For Class 3b, consistent with latest available EPRI data, a non-informative prior distribution is assumed for no “large” failures in 217 tests (i.e., 0.5/(217+1) = 0.0023).

The EPRI methodology contains information concerning the potential that the calculated delta LERF values for several plants may fall above the “very small change” guidelines of the NRC Regulatory Guide 1.174. This information includes a discussion of conservatisms in the quantitative guidance for delta LERF. EPRI describes ways to demonstrate that, using plant-specific calculations, the delta LERF is smaller than that calculated by the simplified method.

The methodology 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 HCGS (as detailed in Section 5) means that the Class 2, Class 7, and Class 8 LERF sequences are subtracted from the CDF that is applied to Class 3b. To be consistent, the same change is made to the Class 3a CDF, even though these events are not considered LERF. Note that Class 2 events refer to sequences with a large pre-existing containment isolation failure that lead to LERF, a subset of Class 7 events are LERF sequences due to an early containment failure from energetic phenomena, and Class 8 are containment bypass events that contribute to LERF.

Consistent with the EPRI methodology [3], the change in the leak detection probability can be estimated by comparing the average time that a leak could exist without detection. For example, the average time that a leak could go undetected with a three-year test interval is 1.5 years (3 yr / 2), and the average time that a leak could exist without detection for a ten-year interval is 5 years (10 yr / 2). This ILRT interval 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, given a 10-year vs. a 3-yr interval. Correspondingly, an extension of the ILRT interval to fifteen years can be estimated to lead to about a factor of 5.0 (7.5/1.5) increase in the non-detection probability of a leak.

HCGS Past ILRT Results

The surveillance frequency for Type A testing in NEI 94-01 under option B criteria is at least once per ten years based on an acceptable performance history (i.e., two consecutive periodic Type A tests at least 24 months apart) where the calculated performance leakage rate was less than 1.0 L_a, and in compliance with the performance factors in NEI 94-01, Section 11.3. Based on the successful completion of two consecutive ILRTs at HCGS, the current ILRT interval is once per ten years [31]. Note that the probability of a pre-existing leakage due to extending the ILRT interval is based on the industry-wide historical results as noted in the EPRI guidance document [3].

EPRI Methodology

This analysis uses the approach outlined in the EPRI Methodology [3]. The six steps of the methodology are:

1. Quantify the baseline (three-year ILRT frequency) risk in terms of frequency per reactor year for the EPRI accident classes of interest.
2. Develop the baseline population dose (person-rem, from the plant PRA or IPE, or calculated based on leakage) for the applicable accident classes.
3. Evaluate the risk impact (in terms of population dose rate and percentile change in population dose rate) for the interval extension cases.
4. Determine the risk impact in terms of the change in LERF.
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, and external event impacts.

The first three steps of the methodology deal with calculating the change in dose. The change in dose is the principal basis upon which the Type A ILRT interval extension was previously granted and is a reasonable basis for evaluating additional extensions. The fourth step in the methodology calculates the change in LERF and compares it to the guidelines in Regulatory Guide 1.174. Because the change in CDF for HCGS is minimal, the change in LERF forms the quantitative basis for a risk informed decision per current NRC practice, namely Regulatory Guide 1.174. The fifth step of the

methodology calculates the change in containment failure probability, referred to as the conditional containment failure probability (CCFP). The NRC has identified a CCFP of less than 1.5% as the acceptance criteria for extending the Type A ILRT test intervals as the basis for showing that the proposed change is consistent with the defense in depth philosophy [7]. As such, this step suffices as the remaining basis for a risk informed decision per Regulatory Guide 1.174. Step 6 takes into consideration the additional risk due to external events, and investigates the impact on results due to varying the assumptions associated with the liner corrosion rate and failure to visually identify pre-existing flaws.

4.4 IMPACT OF EXTENSION ON DETECTION OF STEEL LINER CORROSION THAT LEADS TO LEAKAGE

An estimate of the likelihood and risk implications of corrosion-induced leakage of the steel liners occurring and going undetected during the extended test interval is evaluated using the methodology from the Calvert Cliffs liner corrosion analysis [5]. The Calvert Cliffs analysis was performed for a concrete cylinder and dome and a concrete basemat, each with a steel liner. The HCGS containment is a pressure-suppression BWR/Mark I type with a steel shell in the drywell region, including a portion below the concrete drywell floor. The shell is surrounded by concrete.

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

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

Assumptions

1. Based on a review of industry events, an Oyster Creek incident is assumed to be applicable to HCGS for a concealed shell failure in the floor. In the Calvert Cliffs analysis, this event was assumed not to be applicable and 0.5 failures were assumed (i.e. a typical PRA model when no failures have been identified). For HCGS one failure (rather than 0.5) is assumed for the floor area. (See Table 4.4-1, Step 1, Containment Basement probability calculation.)
2. The two corrosion events over a 5.5 year data period are used to estimate the liner flaw probability in the Calvert Cliffs analysis and are assumed to be applicable to the HCGS containment analysis. These events, one at North Anna Unit 2 and one at Brunswick Unit 2, were initiated from the non-visible (backside) portion of the containment liner. It is noted that two additional events have occurred in recent years (based on a data search covering approximately 9 years documented in Reference [30]). In November 2006, the Turkey Point 4 containment building liner developed a hole when a sump pump support plate was moved. In May 2009, a hole approximately 3/8" by 1" in size was identified in the Beaver Valley Unit 1 containment liner. A second hole was identified in Beaver Valley Unit 1 in 2013. For risk evaluation purposes, these two more recent events occurring over a 9 year period are judged to be adequately represented by the two events in the 5.5 year period of the Calvert Cliffs analysis incorporated in the EPRI guidance (See Table 4.4-1, Step 1).
3. Consistent with the Calvert Cliffs analysis, the steel liner flaw likelihood is assumed to double every five years. This is based solely on judgment and is included in this analysis to address the increased likelihood of corrosion as the steel liner ages (See Table 4.4-1, Steps 2 and 3). Sensitivity studies are included that address doubling this rate every two years and every ten years.
4. In the Calvert Cliffs analysis, the likelihood of the containment atmosphere reaching the outside atmosphere given that a liner flaw exists was estimated as 1.1% for the cylinder and dome region, and 0.11% (10% of the cylinder failure probability) for the basemat. These values were determined from an assessment of the containment fragility curve versus the ILRT test pressure. For HCGS the containment failure probabilities are conservatively assumed to be 10% for the drywell outer walls and 1% for the basemat. Sensitivity studies are included that increase and decrease the probabilities by an order of magnitude. (See Table 4.4-1, Step 4.)
5. Consistent with the Calvert Cliffs analysis, a 5% visual inspection detection failure likelihood given the flaw is visible and a total detection failure likelihood of 10% is used for the containment cylinder and head. For the containment basemat, 100% is assumed unavailable for visual

inspection. To date, all liner corrosion events have been detected through visual inspection (See Table 4.4-1, Step 5). The Calvert Cliffs analysis is based on an estimate of 85% of the interior wall surface being visible for inspection. HCGS estimates that at least 80% of the interior surface of the HCGS containment wall is inspectable based on the Containment ISI Plan [33] . Although this is slightly lower than Calvert Cliff, use of the Calvert Cliff's analysis is considered appropriate. Sensitivity studies are included that evaluate total detection failure likelihood of 5% and 15%, respectively.

6. Consistent with the Calvert Cliffs analysis, all non-detectable containment failures are assumed to result in early releases. This approach avoids a detailed analysis of containment failure timing and operator recovery actions.

TABLE 4.4-1

STEEL LINER CORROSION BASE CASE

<table>
<tr><th>STEP</th><th>DESCRIPTION</th><th colspan="2">CONTAINMENT CYLINDER AND HEAD</th><th colspan="2">CONTAINMENT BASEMAT</th></tr>
<tr><td>1</td><td>Historical Steel Liner Flaw Likelihood
Failure Data: Containment location specific (consistent with Calvert Cliffs analysis).</td><td colspan="2">Events: 2

2/(70 * 5.5) = 5.2E-3</td><td colspan="2">Events: 1
1.0/(70 * 5.5) = 2.6E-3</td></tr>
<tr><td rowspan="2">2</td><td rowspan="2">Age Adjusted Steel Liner Flaw Likelihood
During 15-year interval, assume failure rate doubles every five years (14.9% increase per year). The average for 5th to 10th year is set to the historical failure rate (consistent with Calvert Cliffs analysis).</td><td><u>Year</u>
1
avg 5-10
15</td><td><u>Failure Rate</u>
2.1E-3
5.2E-3
1.4E-2</td><td><u>Year</u>
1
avg 5-10
15</td><td><u>Failure Rate</u>
1.0E-3
2.6E-3
7.0E-3</td></tr>
<tr><td colspan="2">15 year average = 6.27E-3</td><td colspan="2">15 year average = 3.14E-3</td></tr>
<tr><td>3</td><td>Flaw Likelihood at 3, 10, and 15 years
Uses age adjusted liner flaw likelihood (Step 2), assuming failure rate doubles every five years (consistent with Calvert Cliffs analysis – See Table 6 of Reference [5]).</td><td colspan="2">0.71% (1 to 3 years)
4.06% (1 to 10 years)
9.40% (1 to 15 years)
(Note that the Calvert Cliffs analysis presents the delta between 3 and 15 years of 8.7% to utilize in the estimation of the delta-LERF value. For this analysis, the values are calculated based on the 3, 10, and 15 year intervals.)</td><td colspan="2">0.36% (1 to 3 years)
2.03% (1 to 10 years)
4.70% (1 to 15 years)
(Note that the Calvert Cliffs analysis presents the delta between 3 and 15 years of 2.2% to utilize in the estimation of the delta-LERF value. For this analysis, twice that value is utilized (since 1 failure is assumed applicable instead of 0.5) and the values are calculated based on the 3, 10, and 15 year intervals.)</td></tr>
<tr><td>4</td><td>Likelihood of Breach in Containment Given Steel Liner Flaw
The failure probability of the containment cylinder and dome is assumed to be 10% (compared to 1.1% in the Calvert Cliffs analysis). The basemat failure probability is assumed to be a factor of ten less, 1% (compared to 0.11% in the Calvert Cliffs analysis).</td><td colspan="2">10%</td><td colspan="2">1%</td></tr>
</table>

TABLE 4.4-1

STEEL LINER CORROSION BASE CASE

STEP	DESCRIPTION	CONTAINMENT CYLINDER AND HEAD	CONTAINMENT BASEMAT
5	**Visual Inspection Detection Failure Likelihood** Utilize assumptions consistent with Calvert Cliffs analysis.	**10%** 5% failure to identify visual flaws plus 5% likelihood that the flaw is not visible (not through-cylinder but could be detected by ILRT) All events have been detected through visual inspection. 5% visible failure detection is a conservative assumption.	**100%** Cannot be visually inspected.
6	**Likelihood of Non-Detected Containment Leakage** (Steps 3 * 4 * 5)	**0.0071% (at 3 years)** =0.71% * 10% * 10% **0.0406% (at 10 years)** =4.06% * 10% * 10% **0.0940% (at 15 years)** =9.40% * 10% * 10%	**0.0036% (at 3 years)** =0.36% * 1% * 100% **0.0203% (at 10 years)** =2.03% * 1% * 100% **0.0470% (at 15 years)** =4.70% * 1% * 100%

The total likelihood of the corrosion-induced, non-detected containment leakage that is subsequently added to the EPRI Class 3b contribution is the sum of Step 6 for the containment cylinder and dome, and the containment basemat:

- At 3 years: 0.0071% + 0.0036% = 0.0107%
- At 10 years: 0.0406% + 0.0203% = 0.0609%
- At 15 years: 0.0940% + 0.0470% = 0.1410%

5.0 RESULTS

The application of the approach based on EPRI Guidance [3] has led to the following results. The results are displayed according to the eight accident classes defined in the EPRI report. Table 5.0-1 lists these accident classes.

TABLE 5.0-1

ACCIDENT CLASSES

ACCIDENT CLASSES (CONTAINMENT RELEASE TYPE)	DESCRIPTION
1	Containment Intact
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 the HCGS specific accident sequences in which the containment remains intact or the containment is impaired. Specifically, the categorization 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 Class 1 sequences).
- Core damage sequences in which containment integrity is impaired due to random isolation failures of plant components other than those associated with Type B or Type C test components. For example, liner breach or bellows leakage, if applicable. (EPRI Class 3 sequences).

- Core damage sequences in which containment integrity is impaired due to containment isolation failures of pathways left "opened" following a plant post-maintenance test. (For example, a valve failing to close following a valve stroke test. (EPRI Class 6 sequences). Consistent with the EPRI Guidance, this class is not specifically examined since it will not significantly influence the results of this analysis.
- Accident sequences involving containment bypass (EPRI Class 8 sequences), large containment isolation failures (EPRI Class 2 sequences), and small containment isolation "failure-to-seal" events (EPRI 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 base-line risk in terms of frequency per reactor year for each of the accident classes presented in Table 5.0-1.

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

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

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

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

Step 6 Evaluate the sensitivity of the results to assumptions in the liner corrosion analysis, and external event impacts.

It is noted that the calculations were generally performed using an electronic spreadsheet such that the presented numerical results may differ slightly as compared to values calculated by hand.

5.1 STEP 1 – QUANTIFY THE BASE-LINE RISK IN TERMS OF FREQUENCY PER REACTOR YEAR

This step involves the review of the HCGS Level 2 accident sequence frequency results. Table 5.1-1 relates EPRI class containment release scenarios to accident sequence categories used in the SAMA evaluation for the HCGS license renewal application. This application combined with the HCGS dose (person-rem) results mapping documented in Table 4.2-6 forms the basis for estimating the population dose for HCGS.

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-1018243 [3]). 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 5.0-1 were developed for HCGS based on Level 2 PRA inputs found in Section 4, determining the frequencies for Classes 3a and 3b, and then determining the remaining frequency for Class 1. Furthermore, adjustments were made to the Class 3b and hence Class 1 frequencies to account for the impact of undetected corrosion of the steel liner per the methodology described in Section 4.4. The eight containment release class frequencies were developed consistent with the definitions in Table 5.0-1 as described following Table 5.1-1.

Table 5.1-1 provides dose values for each EPRI scenario class. The dose values were developed in Section 4.2. The Level 2 Accident sequence bin(s) assigned to each EPRI Class are described under each containment release class discussion following Table 5.1-1. The methodology for determining the dose applied to EPRI Class 7 is further described under the paragraph heading “Class 7 Sequences”.

TABLE 5.1-1

EPRI CLASS DOSE ASSIGNMENT FROM THE HCGS SAMA CONSEQUENCE MODEL

EPRI SCENARIO CLASS	LEVEL 2 ACCIDENT SEQUENCE BIN	POPULATION DOSE (PERSON-REM)[(3)]
1	ST11 (Containment Intact)	1.01E+03
2	ST3[(1)] (Isolation Failure)	2.34E+07
7	All EPRI Class 7a through 7f Level 2 bins	
7a (H/E - HP)	ST1 (H/E)	1.82E+07
7b (H/E - LP)	ST2 (H/E)	1.38E+07
7c (H/I)	ST4 (H/I)	8.75E+06
7d (H/L)	ST5 (H/L)	1.10E+07
7e (M/E)	ST6 (M/E)	1.31E+07
7f (M/I)	ST7 (M/I)	6.34E+06
7g (M/L)	ST8 (M/L)	6.38E+06
7h (L/E, LL/E, L/I, or LL/I)	ST9 (L/E, LL/E, L/I, or LL/I)	6.44E+03
7i (L/L, LL/L)	ST10 (L/L, LL/L)	6.87E+05
8	ST3 (H/E - BOC)	2.34E+07

Notes to Table 5.1-1:

(1) HCGS SAMA sequence ST3 represents the highest containment bypass dose.

(2) Given that multiple HCGS discrete scenarios apply to the broader EPRI Class 7, the EPRI dose is based on a weighted average based on HC111A scenario frequencies. The weighted average dose is developed in Table 5.1-2.

(3) Values are from the SAMA dose analysis for the EPRI category as discussed in Section 4.2 and Table 4.2-7. No adjustments were required for population, power level, or containment leakage rate.

Class 1 Sequences

This group consists of all core damage accident progression bins for which the containment remains intact (modeled as Technical Specification Leakage). The frequency per year for these sequences is 3.76E-07/yr and is determined by subtracting all containment failure end states including the EPRI/NEI Class 3a and 3b frequency calculated below, from the total CDF.

Class 1 = CDF – (EPRI Classes)
= 4.21E-06 – (3.23E-07 (class 2) + 3.42E-08 (3a) + 8.55E-09 (3b) + 3.52E-07 (7 LERF) + 2.15E-06 (7-Non-LERF) + 1.69E-07 (Class 8))
= 1.17E-06/yr (from Excel™ spreadsheet calculation)

For this analysis, the associated maximum containment leakage for this group is 1 L_a, consistent with an intact containment evaluation.

Class 2 Sequences

This group consists of containment isolation failures. For HCGS, all containment isolation failure sequences result in a large early release and were assigned to accident sequence bin H/E (LERF). The HCGS L2 Sequences associated with containment isolation failure leading to a large early release are the following: IA1-43, IBE1-43, IC1-43, ID1-43, 3B-041, and 3C-041. The sum of the frequencies of these scenarios is 3.23E-07/yr. For HCGS one containment isolation failure sequence (IBL1-43) was not included because this sequence is assessed as a non-early release. Sequence IBL1-43 is included in the Class 7 sequences categorized as ST4 H/I accident sequences. Note that Class 2 frequency is not affected by the ILRT interval change.

Class 3 Sequences

This group represents pre-existing leakage in the containment structure (e.g., containment liner). The containment leakage for these sequences can be either small

(in excess of design allowable but <10La) or large. In this analysis, a value of 10 L_a was used for small pre-existing flaws and 100 L_a for relatively large flaws.

The respective frequencies per year are determined as follows:

$PROB_{Class\_3a}$	= probability of small pre-existing containment liner leakage
	= 0.0092 (see Section 4.3)
$PROB_{Class\_3b}$	= probability of large pre-existing containment liner leakage
	= 0.0023 (see Section 4.3)

As described in Section 4.3, additional consideration is made to not apply these failure probabilities to those cases that are already considered LERF scenarios (i.e., the Class 2 and Class 8 contributions). Note that some portion of the EPRI Class 7 frequency also represents LERF scenarios, but these are conservatively not subtracted from that portion of CDF eligible for EPRI Class 3. Additionally, CDF associated with failures that would never lead to LERF (e.g., Class II and Class IBL sequences) could also be excluded from EPRI Class 3a, but this is conservatively not performed. The adjustment to exclude EPRI Class 2 and Class 8 is made on the frequency information as shown below.

Class_3a = 0.0092 * [CDF – (Class 2 + Class 8)]
= 0.0092 * [4.21E-06 – (3.23E-07 + 1.69E-07)]
= 3.42E-08/yr

Class_3b = 0.0023 * [CDF – (Class 2 + Class 8)]
= 0.0023 * [4.21E-06 – (3.23E-07 + 1.69E-07)]
= 8.55E-09/yr

For this analysis, the associated containment leakage for Class 3a is 10 L_a and 100 L_a for Class 3b, which is consistent with the latest EPRI methodology [3] and the NRC SE [7].

Class 4 Sequences

This group represents containment isolation failure-to-seal of Type B test components. Because these failures are detected by Type B tests which are unaffected by the Type A ILRT, this group is not evaluated any further in this analysis.

Class 5 Sequences

This group represents containment isolation failure-to-seal of Type C test components. Because these failures are detected by Type C tests which are unaffected by the Type A ILRT, this group is not evaluated any further in this analysis.

Class 6 Sequences

This group is similar to Class 2. These are sequences that involve core damage with a failure-to-seal containment leakage due to failure to isolate the containment. These sequences are dominated by misalignment of containment isolation valves following a test/maintenance evolution. Consistent with the EPRI guidance [3], this accident class is not explicitly considered since it has a negligible impact on the results.

Class 7 Sequences

This group consists of all core damage accident progression bins in which containment failure induced by severe accident phenomena occurs. Note that containment failure is not induced for containment bypass (BOC and ISLOCA) (EPRI Class 8) and isolation failure (EPRI Class 2) sequences as these are either the initiating event or a plant condition, existing at the time of the initiating event. For this analysis, the associated radionuclide releases are based on the application of the Level 2 end states from the HCGS SAMA evaluation as described in Section 4.2. The Class 7 Sequences are all Level 2 Sequences except containment intact EPRI Class 1, the containment bypass (EPRI Class 8) and isolation failure (EPRI Class 2) sequences leading to a large early release. The failure frequency and population dose for each specific release category is shown below in Table 5.1-2. The total release frequency and total dose are then used to determine a weighted average person-rem. The resulting weighted average person-

rem is the representative EPRI Class 7 dose in the subsequent analysis. Note that the total frequency and dose associated from this EPRI class does not change as part of the ILRT extension request.

TABLE 5.1-2

ACCIDENT CLASS 7 FAILURE FREQUENCIES AND POPULATION DOSES (HCGS BASE CASE LEVEL 2 MODEL)

ACCIDENT CLASS	SAMA RELEASE CATEGORY	HC111A PRA RELEASE FREQUENCY / YR	POPULATION DOSE (50 MILES) PERSON-REM [(1)]	POPULATION DOSE RISK (50 MILES) (PERSON-REM / YR)[(2)]
EPRI #7a (H/E - HP)	ST1	2.81E-07	1.82E+07	5.11E+00
EPRI #7b (H/E - LP)	ST2	7.08E-08	1.38E+07	9.78E-01
EPRI #7c (H/I)	ST4	1.02E-06	8.75E+06	8.93E+00
EPRI #7d (H/L)	ST5	1.16E-12	1.10E+07	1.28E-05
EPRI #7e (M/E)	ST6	4.58E-07	1.31E+07	6.00E+00
EPRI #7f (M/I)	ST7	3.18E-07	6.34E+06	2.02E+00
EPRI #7g (M/L)	ST8	0.00E+00	6.38E+06	0.00E+00
EPRI #7h (L/E, LL/E, L/I, LL/I)	ST9	3.42E-07	6.44E+03	2.20E-03
EPRI #7i (L/L, LL/L)	ST10	1.51E-08	6.87E+05	1.04E-02
Class 7 Total	**--**	**2.50E-06[(4)]**	**9.20E+06[(3)]**	**2.30E+01**

Notes to Table 5.1-2:

(1) Population dose values from Table 5.1-1.

(2) Obtained by multiplying the Release Frequency per year by the Population Dose Person-Rem value. Calculations were performed using more than 3 significant figures. Therefore, figures may differ in the 3rd digit if one multiples the figures shown above.

(3) The weighted average population dose for Class 7 is obtained by dividing the total population dose risk by the total release frequency.

(4) Totals are from EXCEL spreadsheet using more than 3 significant figures.

Class 8 Sequences

This group represents sequences where containment bypass occurs (BOC, ISLOCA). For HCGS, all containment bypass sequences were assigned ST3 dose results. The sum of the frequencies of these scenarios is 1.69E-07/yr.

Summary of Accident Class Frequencies

In summary, the accident sequence frequencies that can lead to release of radionuclides to the public have been derived in a manner consistent with the definition of accident classes defined in EPRI 1018243 [3] and are shown in Table 5.1-3 by accident class.

TABLE 5.1-3

RADIONUCLIDE RELEASE FREQUENCIES AS A FUNCTION OF ACCIDENT CLASS (HCGS BASE CASE)

ACCIDENT CLASSES (CONTAINMENT RELEASE TYPE)	DESCRIPTION	FREQUENCY (PER RX-YR)
1	No Containment Failure	1.17E-06
2	Large Isolation Failures (Failure to Close)	3.23E-07
3a	Small Isolation Failures (liner breach)	3.42E-08
3b	Large Isolation Failures (liner breach)	8.55E-09
4	Small Isolation Failures (Failure to seal –Type B)	N/A
5	Small Isolation Failures (Failure to seal—Type C)	N/A
6	Other Isolation Failures (e.g., dependent failures)	N/A
7	Failures Induced by Phenomena (Early and Late)	2.50E-06
8	Bypass (Interfacing System LOCA)	1.69E-07
CDF	**All CET End states (including very low and no release)**	**4.21E-06**

5.2 STEP 2 – DEVELOP PLANT-SPECIFIC PERSON-REM DOSE (POPULATION DOSE) PER REACTOR YEAR

Plant-specific release analyses were performed to estimate the person-rem doses to the population within a 50-mile radius from the plant. The releases are based on information provided by Appendix E of the Severe Accident Mitigation Alternatives (SAMA) analysis

of the HCGS License Renewal Report [8]. The results of applying these releases to the EPRI/NEI containment failure classification are as follows:

Class 1	=	1.01E+03 person-rem (at 1.0 L_a)[(1)]	
Class 2	=	2.43E+07 person-rem[(2)]	
Class 3a	=	6.06E+03 person-rem x 10 L_a =	1.01E+04 person-rem[(3)]
Class 3b	=	6.06E+03 person-rem x 100 L_a =	1.01E+04 person-rem[(3)]
Class 4	=	Not analyzed	
Class 5	=	Not analyzed	
Class 6	=	Not analyzed	
Class 7	=	9.20E+06 person-rem[(4)]	
Class 8	=	2.34E+06 person-rem[(5)]	

In summary, the population dose estimates derived for use in the risk evaluation per the EPRI methodology [3] containment failure classifications are provided in Table 5.2-1.

(1) The Class 1, containment intact sequences, dose is assigned from the HCGS SAMA sequence ST11 (Containment Intact) from the SAMA Level 3 adjusted dose for HCGS as shown in Table 5.1-1.

(2) The Class 2, containment isolation failures, dose is approximated from HCGS SAMA sequence ST3 (H/E – BOC) from Table 5.1-1.

(3) The Class 3a and 3b dose are related to the leakage rate as shown, based on the EPRI methodology.

(4) The Class 7 dose is assigned from the weighted average dose calculated from HCGS SAMA sequence bins ST1, ST2, ST4, ST5, ST6, ST7, ST8, ST9 and ST10 from Table 5.1-1 as detailed in Table 5.1-2 above.

(5) Class 8 sequences involve containment bypass failures; as a result, the person-rem dose is not based on normal containment leakage. The releases for this class are assigned from HCGS SAMA sequence bin ST3 from Table 5.1-1.

TABLE 5.2-1
HCGS POPULATION DOSE ESTIMATES FOR POPULATION WITHIN 50 MILES

EPRI ACCIDENT CLASSES (CONTAINMENT RELEASE TYPE)	REPRESENTATIVE ACCIDENT PROGRESSION	DESCRIPTION	PERSON-REM (50 MILES)
1	Containment Intact	No Containment Failure ($1\ L_a$)	1.01E+03
2	H/E (isolation failure; non-BOC, non-ISLOCA)	Large Isolation Failures (Failure to Close)	2.43E+07
3a	$10\ L_a$	Small Isolation Failures (liner breach)	6.06E+04
3b	$100\ L_a$	Large Isolation Failures (liner breach)	6.06E+05
4	N/A	Small Isolation Failures (Failure to seal –Type B)	NA
5	N/A	Small Isolation Failures (Failure to seal—Type C)	NA
6	N/A	Other Isolation Failures (e.g., dependent failures)	NA
7	See Table 5.1-2 (All releases except isolation, and bypass sequences)	Failures Induced by Phenomena (Early and Late)	9.20E+06
8	H/E (BOC, ISLOCA)	Bypass (Break Outside Containment or Interfacing System LOCA)	2.34E+07

The above dose estimates, when combined with the frequency results presented in Table 5.1-3, yield the HCGS baseline mean consequence measures for each accident class. These results are presented in Table 5.2-2.

TABLE 5.2-2

HCGS ANNUAL DOSE AS A FUNCTION OF ACCIDENT CLASS; CHARACTERISTIC OF CONDITIONS FOR 3 IN 10 YEAR ILRT FREQUENCY

ACCIDENT CLASSES (CONT. RELEASE TYPE)	DESCRIPTION	PERSON-REM (0-50 MILES)	EPRI METHODOLOGY		EPRI METHODOLOGY PLUS CORROSION		CHANGE DUE TO CORROSION (PERSON-REM/YR)(1)
			FREQUENCY (1/YR)	PERSON-REM/YR (0-50 MILES)	FREQUENCY (1/YR)	PERSON-REM/YR (0-50 MILES)	
1	Containment Intact (2)	1.01E+03	1.17E-06	1.18E-03	1.17E-06	1.18E-03	-4.00E-07
2	Large Isolation Failures (Failure to Close)	2.34E+07	3.23E-07	7.56E+00	3.23E-07	7.56E+00	--
3a	Small Isolation Failures (liner breach)	1.01E+04	3.42E-08	3.45E-04	3.42E-08	3.45E-04	--
3b	Large Isolation Failures (liner breach)	1.01E+05	8.55E-09	8.64E-04	8.95E-09	9.04E-04	4.00E-05
7	Failures Induced by Phenomena (Early and Late)	9.20E+06	2.50E-06	2.30E+01	2.50E-06	2.30E+01	--
8	Containment Bypass (Interfacing System LOCA)	2.34E+07	1.69E-07	3.95E+00	1.69E-07	3.95E+00	--
CDF	**All CET end states**		**4.21E-06**	**34.564**	**4.21E-06**	**34.564**	**3.96E-05**

Notes to Table 5.2-2:

(1) Only release Classes 1 and 3b are affected by the corrosion analysis. During the 15-year interval, the failure rate is assumed to double every five years. The additional frequency added to Class 3b is subtracted from Class 1 and the population dose rates are recalculated. This results in a small reduction to the Class 1 dose rate and an increase to the Class 3b dose rate.

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

5.3 STEP 3 – EVALUATE RISK IMPACT OF EXTENDING TYPE A TEST INTERVAL FROM 10-TO-15 YEARS

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

Risk Impact Due to 10-year Test Interval

As previously stated, Type A tests impact only Class 3 sequences. For Class 3 sequences, the release magnitude is not impacted by the change in test interval (a small or large breach remains the same, even though the probability of not detecting the breach increases). Thus, only the frequency of Class 3a and 3b sequences is impacted. The risk contribution is changed based on the EPRI guidance as described in Section 4.3 by a factor of 3.33 compared to the base case values. The results of the calculation for a 10-year interval are presented in Table 5.3-1.

Risk Impact Due to 15-Year Test Interval

The risk contribution for a 15-year interval is calculated in a manner similar to the 10-year interval. The difference is in the increase in probability of not detecting a leak in Classes 3a and 3b. For this case, the value used in the analysis is a factor of 5.0 compared to the 3-year interval value, as described in Section 4.3. The results for this calculation are presented in Table 5.3-2.

TABLE 5.3-1

HCGS ANNUAL DOSE AS A FUNCTION OF ACCIDENT CLASS; CHARACTERISTIC OF CONDITIONS FOR 1 IN 10 YEAR ILRT FREQUENCY

ACCIDENT CLASSES (CONT. RELEASE TYPE)	DESCRIPTION	PERSON-REM (0-50 MILES)	EPRI METHODOLOGY		EPRI METHODOLOGY PLUS CORROSION		CHANGE DUE TO CORROSION (PERSON-REM/YR) [1]
			FREQUENCY (1/YR)	PERSON-REM/YR (0-50 MILES)	FREQUENCY (1/YR)	PERSON-REM/YR (0-50 MILES)	
1	Containment Intact [2]	1.01E+03	1.07E-06	1.08E-03	1.07E-06	1.08E-03	-2.29E-06
2	Large Isolation Failures (Failure to Close)	2.34E+07	3.23E-07	7.56E+00	3.23E-07	7.56E+00	--
3a	Small Isolation Failures (liner breach)	1.01E+04	1.14E-07	1.15E-03	1.14E-07	1.15E-03	--
3b	Large Isolation Failures (liner breach)	1.01E+05	2.85E-08	2.88E-03	3.07E-08	3.10E-03	2.29E-04
7	Failures Induced by Phenomena (Early and Late)	9.20E+06	2.50E-06	2.30E+01	2.50E-06	2.30E+01	--
8	Containment Bypass (Interfacing System LOCA)	2.34E+07	1.69E-07	3.95E+00	1.69E-07	3.95E+00	--
CDF	**All CET end states**		**4.21E-06**	34.567	**4.21E-06**	34.567	**2.26E-04**

Notes to Table 5.3-1:

(1) Only release Classes 1 and 3b are affected by the corrosion analysis. During the 15-year interval, the failure rate is assumed to double every five years. The additional frequency added to Class 3b is subtracted from Class 1 and the population dose rates are recalculated. This results in a small reduction to the Class 1 dose rate and an increase to the Class 3b dose rate.

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

TABLE 5.3-2

HCGS ANNUAL DOSE AS A FUNCTION OF ACCIDENT CLASS; CHARACTERISTIC OF CONDITIONS FOR 1 IN 15 YEAR ILRT FREQUENCY

ACCIDENT CLASSES (CONT. RELEASE TYPE)	DESCRIPTION	PERSON-REM (0-50 MILES)	EPRI METHODOLOGY		EPRI METHODOLOGY PLUS CORROSION		CHANGE DUE TO CORROSION (PERSON-REM/YR) [1]
			FREQUENCY (1/YR)	PERSON-REM/YR (0-50 MILES)	FREQUENCY (1/YR)	PERSON-REM/YR (0-50 MILES)	
1	Containment Intact [2]	1.01E+03	1.00E-06	1.01E-03	9.94E-07	1.00E-03	-5.29E-06
2	Large Isolation Failures (Failure to Close)	2.34E+07	3.23E-07	7.56E+00	3.23E-07	7.56E+00	--
3a	Small Isolation Failures (liner breach)	1.01E+04	1.71E-07	1.73E-03	1.71E-07	1.73E-03	--
3b	Large Isolation Failures (liner breach)	1.01E+05	4.28E-08	4.32E-03	4.80E-08	4.85E-03	5.29E-04
7	Failures Induced by Phenomena (Early and Late)	9.20E+06	2.50E-06	2.30E+01	2.50E-06	2.30E+01	--
8	Containment Bypass (Interfacing System LOCA)	2.34E+07	1.69E-07	3.95E+00	1.69E-07	3.95E+00	--
CDF	**All CET end states**		**4.21E-06**	34.568	**4.21E-06**	34.569	**5.24E-04**

Notes to Table 5.3-2:

(1) Only release Classes 1 and 3b are affected by the corrosion analysis. During the 15-year interval, the failure rate is assumed to double every five years. The additional frequency added to Class 3b is subtracted from Class 1 and the population dose rates are recalculated. This results in a small reduction to the Class 1 dose rate and an increase to the Class 3b dose rate.

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

5.4 STEP 4 – DETERMINE THE CHANGE IN RISK IN TERMS OF LARGE EARLY RELEASE FREQUENCY

Regulatory Guide 1.174 provides guidance for determining the risk impact of plant-specific changes to the licensing basis. RG 1.174 defines “very small” changes in risk as resulting in increases of core damage frequency (CDF) below 1E-06/yr and increases in LERF below 1E-07/yr, and “small” changes in LERF as below 1E-06/yr. Because the ILRT for HCGS has only a minor impact on CDF, the relevant metric is LERF.

For HCGS, 100% of the frequency of Class 3b sequences can be used as a conservative first-order estimate to approximate the potential increase in LERF from the ILRT interval extension (consistent with the EPRI guidance methodology and the NRC SE). Based on the original 3-in-10 year test interval assessment from Table 5.2-2, the Class 3b frequency is 8.95E-09/yr, which includes the corrosion effect of the containment liner. Based on a ten-year test interval from Table 5.3-1, the Class 3b frequency is 3.07E-08/yr; and, based on a fifteen-year test interval from Table 5.3-2, it is 4.80E-08/yr. Thus, the increase in the overall probability of LERF due to Class 3b sequences that is due to increasing the ILRT test interval from 3 to 15 years (including corrosion effects) is 3.91E-08/yr. Similarly, the increase in LERF due to increasing the interval from 10 to 15 years (including corrosion effects) is 1.73E-08/yr. As can be seen, even with the conservatisms included in the evaluation (per the EPRI methodology), the estimated change in LERF is well within Region III of Figure 4 of Reference [4] (i.e., the acceptance criteria for “very small” changes in LERF) when comparing the 15 year results to the original 3-in-10 year requirement.

5.5 STEP 5 – DETERMINE THE IMPACT ON THE CONDITIONAL CONTAINMENT FAILURE PROBABILITY

Another parameter that can provide input into the decision-making process is the change in the conditional containment failure probability (CCFP). The change in CCFP is indicative of the effect of the ILRT on all radionuclide releases, not just LERF. The CCFP can be calculated from the results of this analysis. One of the difficult aspects of this calculation is providing a definition of the “failed containment.” In this assessment, the CCFP is defined such that containment failure includes all radionuclide release end states other than the intact state and, consistent with the EPRI guidance, the small isolation failures (Class 3a). The conditional part of the definition is conditional given a severe accident (i.e., core damage).

The change in CCFP can be calculated by using the method specified in the EPRI methodology [3]. The NRC SE has noted a change in CCFP of <1.5% as the acceptance criterion to be used as the basis for showing that the proposed change is consistent with the defense-in-depth philosophy. Table 5.5-1 shows the CCFP values that result from the assessment for the various testing intervals including corrosion effects in which the flaw rate is assumed to double every five years. The CCFP is calculated as follows:

CCFP = [1 – (Class 1 frequency + Class 3a frequency)/CDF] x 100%

TABLE 5.5-1

HCGS ILRT CONDITIONAL CONTAINMENT FAILURE PROBABILITIES

CCFP 3 IN 10 YRS	**CCFP 1 IN 10 YRS**	**CCFP 1 IN 15 YRS**	**ΔCCFP$_{15-3}$**	**ΔCCFP$_{15-10}$**
71.39%	71.91%	72.32%	0.93%	0.41%

The change in CCFP of about 1% as a result of extending the test interval to 15 years from the original 3-in-10 year requirement is judged to be relatively insignificant, and is less than the NRC SE acceptance criteria of < 1.5%.

5.6 SUMMARY OF INTERNAL EVENTS RESULTS

Table 5.6-1 summarizes the internal events results of this ILRT extension risk assessment for HCGS. The results between the 3-in-10 year interval and the 15 year interval compared to the acceptance criteria are then shown in Table 5.6-2, and it is demonstrated that the acceptance criteria are met.

TABLE 5.6-1

HCGS ILRT CASES: BASE, 3 TO 10, AND 3 TO 15 YR EXTENSIONS (INCLUDING AGE ADJUSTED STEEL LINER CORROSION LIKELIHOOD)

EPRI CLASS	DOSE PER-REM	BASE CASE 3 IN 10 YEARS		EXTEND TO 1 IN 10 YEARS		EXTEND TO 1 IN 15 YEARS	
		CDF (1/YR)	PERSON-REM/YR	CDF (1/YR)	PERSON-REM/YR	CDF (1/YR)	PERSON-REM/YR
1	1.01E+03	1.17E-06	1.18E-03	1.07E-06	1.08E-03	9.94E-07	1.00E-03
2	2.34E+07	3.23E-07	7.56E+00	3.23E-07	7.56E+00	3.23E-07	7.56E+00
3a	1.01E+04	3.42E-08	3.45E-04	1.14E-07	1.15E-03	1.71E-07	1.73E-03
3b	1.01E+05	8.95E-09	9.04E-04	3.07E-08	3.10E-03	4.80E-08	4.85E-03
7	9.20E+06	2.50E-06	2.30E+01	2.50E-06	2.30E+01	2.50E-06	2.30E+01
8	2.34E+07	1.69E-07	3.95E+00	1.69E-07	3.95E+00	1.69E-07	3.95E+00
Total		**4.21E-06**	**34.564**	**4.21E-06**	**34.567**	**4.21E-06**	**34.569**
ILRT Dose Rate (person-rem/yr) from 3a and 3b		1.25E-03		4.26E-03		6.58E-03	
Delta Total Dose Rate[1]	From 3 yr	---		2.90E-03		5.15E-03	
	From 10 yr	---		---		2.24E-03	
3b Frequency (LERF)		8.95E-09		3.07E-08		4.80E-08	
Delta 3b LERF	From 3 yr	---		2.18E-08		3.91E-08	
	From 10 yr	---		---		1.73E-08	
CCFP %		71.39%		71.91%		72.32%	
Delta CCFP %	From 3 yr	---		0.52%		0.93%	
	From 10 yr	---		---		0.41%	

Note to Table 5.6-1:

(1) The overall difference in total dose rate is less than the difference of only the 3a and 3b categories between two testing intervals. This is due to the fact that the Class 1 person-rem/yr decreases when extending the ILRT frequency.

TABLE 5.6-2

HCGS ILRT EXTENSION RESULTS COMPARISON TO ACCEPTANCE CRITERIA

FIGURE OF MERIT - >	ΔLERF	ΔPERSON-REM/YR	ΔCCFP
HCGS	4.85E-9/yr	5.15E-03/yr (0.01%)	0.93%
Acceptance Criteria	**<1.0E-7/yr (“very small”)**	**<1.0 person-rem/yr or <1.0%**	**<1.5%**

5.7 EXTERNAL EVENTS CONTRIBUTION

Since the risk acceptance guidelines in RG 1.174 are intended for comparison with a full-scope assessment of risk, including internal and external events, a bounding analysis of the potential impact from external events is presented here.

External hazards were evaluated in the HCGS Individual Plant Examination of External Events (IPEEE) submittal in response to the NRC IPEEE Program (Generic Letter 88-20, Supplement 4) [20]. The IPEEE Program was a one-time review of external hazard risk and was limited in its purpose to the identification of potential plant vulnerabilities and the understanding of associated severe accident risks.

The results of the HCGS IPEEE study are documented in the HCGS IPEEE Main Report [21] and related correspondence. The primary areas of external event evaluation at HCGS were internal fire and seismic. The internal fire events were addressed by using the EPRI Fire Induced Vulnerability Evaluation (FIVE) methodology [22] and the guidance provided in the EPRI Fire PRA Implementation Guide [32]. The seismic evaluations were performed in accordance with the EPRI Seismic Margins Analysis (SMA) methodology [23].

The IPEEE seismic evaluation includes CDF results but no LERF results. More recent bounding seismic CDF values from the NRC have been made public as part of the development of a generic issue report. Referencing the Risk Assessment for NRC GI-199 [28], Table D-1 lists the postulated core damage frequencies using the updated 2008 USGS Seismic Hazard Curves. The weakest link model using the curve for HCGS

resulted in a CDF of 2.80E-06/yr. This value is utilized for the bounding external events assessment provided here.

In addition to internal fires and seismic events, the HCGS IPEEE Submittal analyzed a variety of other external hazards:

- High Winds/Tornadoes
- External Flooding
- Transportation and Nearby Facility Accidents
- Other External Hazards

The HCGS IPEEE analysis of high winds, tornadoes, external floods, transportation accidents, nearby facility accidents, and other external hazards was accomplished by reviewing the plant environs against regulatory requirements regarding these hazards. Based upon this review, it was concluded that HCGS meets the applicable Standard Review Plan requirements and therefore has an acceptably low risk with respect to these hazards. As such, these hazards were determined in the HCGS IPEEE to be negligible contributors to overall plant risk.

Accordingly, these other external event hazards are not included explicitly in this section and are reasonably assumed not to impact the results or conclusions of the ILRT interval extension risk assessment.

5.7.1 HCGS Fire Risk Discussion

A quantifiable Fire PRA model meeting an appropriate level of ASME/ANS Standard [19] was developed for HCGS. The HCGS Fire PRA was peer reviewed in 2010 and updated to address the peer review F&Os in 2015. The results of the 2015 update are judged to be adequate to support the ILRT External Events quantitative risk assessment.

The HCGS FPRA model has both CDF and LERF results. The FPRA model does not include full Level 2 results, therefore the LERF results are used in this analysis.

Attributes of Fire PRA

Fire PRAs are useful tools to identify design or procedural items as areas of focus for improving the safety of the plant. Fire PRAs use a structure and quantification technique similar to that used in the internal events PRA.

Historically, since less attention has been paid to fire PRAs, conservative modeling is common in a number of areas of the fire analysis to provide a “bounding” methodology for fires. This concept is contrary to the base internal events PRA which has had more analytical development and is closer to a realistic assessment (i.e., not conservative) of the plant.

There are a number of fire PRA topics involving technical inputs, data, and modeling that prevent the effective comparison of the calculated core damage frequency figure of merit between the internal events PRA and the fire PRA. These areas are identified as follows:

- **Initiating Events**: The frequency of fires and their severity are generally conservatively overestimated. A revised NRC fire events database indicates the trend toward both lower frequency and less severe fires. This trend reflects the improved housekeeping, reduction in transient fire hazards, and other improved fire protection steps at nuclear utilities.
- **System Response**: Fire protection measures such as sprinklers, CO_2, and fire brigades may be given minimal (conservative) credit in their ability to limit the spread of a fire. Therefore, the severity of the fire and its impact on requirements is exacerbated.

  In addition, cable routings are typically characterized conservatively because of the lack of data regarding the routing of cables or the lack of the analytic modeling to represent the different routings. This leads to limited credit for balance of plant systems that are important for core damage mitigation.
- **Sequences**: Sequences may subsume a number of fire scenarios to reduce the analytic burden. The subsuming of initiators and sequences is

done to envelope those sequences included. This causes additional conservatism.

- **Fire Modeling**: Fire damage and fire propagation are conservatively characterized in most cases. Fire modeling presents bounding approaches regarding the fire immediate effects (e.g., all cables in a tray are always failed for a cable tray fire) and fire propagation.

The fire PRA is subject to more modeling uncertainty than the internal events PRA evaluations. While the fire PRA is generally self-consistent within its calculational framework, the fire PRA calculated quantitative risk metric does not compare well with internal events PRAs because of the number of conservatisms that have been included in the fire PRA process. Therefore, the use of the fire PRA figure of merit as a reflection of CDF may be inappropriate. Any use of fire PRA results and insights should properly reflect consideration of the fact that the “state of the technology” in fire PRAs is less evolved than the internal events PRA.

Relative modeling uncertainty is expected to narrow substantially in the future as more experience is gained in the development and implementation of methods and techniques for modeling fire accident progression and the underlying data.

The breakdown of the HCGS fire risk results are as follows [29]:

TABLE 5.7-1

HCGS FIRE RISK PROFILE

METRIC	FREQUENCY (/YR)	TRUNCATION
CDF	2.18E-05	1E-11
LERF	3.08E-06	1E-12

5.7.2 HCGS Seismic Risk Discussion

A quantifiable seismic PRA model for HCGS has not yet been developed for general use in risk applications. However, recent information is available from the NRC. A Risk Assessment for NRC GI-199 “Implications of Updated Probabilistic Seismic Hazard

Estimates in Central and Eastern United States (CEUS) on Existing Plants," [28], Table D-1 lists the postulated core damage frequencies using the updated 2008 USGS Seismic Hazard Curves. For HCGS, the Seismic Hazard CDF using the "Weakest Link" is 2.8E-06/yr. Given that seismic CDF contributions (e.g., by accident class) are not available, seismic LERF will be estimated by assuming the FPIE CDF contributions to LERF also apply to the seismic LERF.

For CDF, the seismic CDF is a factor of 0.67 less than FPIE CDF (i.e., 2.8E-06 / 4.20E-06). Given this, it is reasonable to assume that the total CDF impact from seismic risk can be approximated by assuming a factor of 0.67 additional contribution to CDF compared to the internal events evaluation alone. Using a base FPIE LERF value of 8.45E-07/yr and multiplying by 0.67 for seismic, gives a total LERF estimate for the seismic PRA model of 5.63E-07/yr.

The assumptions regarding the CDF and LERF values provided above are used to provide insight into the impact of the total external hazard risk on the conclusions of this ILRT risk assessment.

5.7.3 Other External Events Discussion

In addition to internal fires and seismic events, the HCGS IPEEE Submittal analyzed a variety of other external hazards:

- High Winds/Tornadoes
- External Floods
- Transportation and Nearby Facility Accidents

The HCGS IPEEE analysis of high winds, tornadoes, external floods, transportation accidents, and nearby facility accidents was accomplished by reviewing the plant environs against regulatory requirements regarding these hazards. Based upon this review, it was concluded that HCGS meets the applicable NRC Standard Review Plan requirements and therefore has an acceptably low risk with respect to these hazards.

Based on the other external events being low risk contributors (compared to fire and seismic events) the increase in the HCGS other external events risk due to the ILRT extension is reasonably assumed to not impact the results or conclusions of the risk assessment.

5.7.4 External Events Impact Summary

In summary, the seismic and fire CDF values described above results in an external events bounding risk estimate of 2.46E-05/yr. Seismic and Fire LERF values derived from CDF values in sections 5.7.2 and 5.7.3 and as shown in Table 5.7-3 below sum to LERF value of 3.64E-06/yr, which is 4.3 times higher than the internal events LERF.

Table 5.7-3 summarizes the estimated bounding external events CDF contribution for HCGS.

TABLE 5.7-3

HCGS EXTERNAL EVENTS CONTRIBUTOR SUMMARY

EXTERNAL EVENT INITIATOR GROUP	CDF (1/YR)	LERF (1/YR)
Fire	2.18E-05	3.08E-06
Seismic	2.8E-06	5.63E-07
High Winds	Screened	Screened
Other Hazards	Screened	Screened
Total For External Events (for initiators with CDF/LERF available)	**2.46E-05**	**3.64E-06**
Internal Events	4.20E-06	8.45E-07

As noted earlier, the 3b contribution is approximately proportional to CDF. An increase in CDF would likely lead to higher 3b frequency and assumed LERF. To determine a suitable multiplier of external CDF to internal event CDF, a weighted average approach will be used.

TABLE 5.7-4

HCGS EXTERNAL EVENTS TO INTERNAL EVENTS COMPARISON

EVENT INITIATOR GROUP	CDF (1/YR)	LERF (1/YR)
Fire	2.18E-6	3.08E-6
Seismic	2.80E-6	5.63E-7
Total	**2.46E-5**	**3.64E-06**
Weighted Average (External Event to FPIE Multipler)	**5.9**	**4.3**

5.7.5 External Events Impact on ILRT Extension Assessment

The EPRI Category 3b frequency for the 3-per-10 year, 1-per-10 year, and 1-per-15 year ILRT intervals are shown in Table 5.6-1 as 6.89E-09/yr, 2.37E-08/yr, and 3.70E-08/yr, respectively. Using an the conservative CDF external events multiplier of 5.9 (multiplier from Table 5.7-4) for HCGS, the change in the LERF risk measure due to extending the ILRT from 3-per-10 years to 1-per-15 years, including both internal and external hazards risk, is estimated as shown in Table 5.7-5.

TABLE 5.7-5

HCGS 3B (LERF/YR) AS A FUNCTION OF ILRT FREQUENCY FOR INTERNAL AND EXTERNAL EVENTS
(INCLUDING AGE ADJUSTED STEEL LINER CORROSION LIKELIHOOD)

	3B FREQUENCY (3-PER-10 YR ILRT)	3B FREQUENCY (1-PER-10 YEAR ILRT)	3B FREQUENCY (1-PER-15 YEAR ILRT)	LERF INCREASE[1]
Internal Events Contribution	8.95E-09	3.07E-08	4.80E-08	3.91E-08
External Events Contribution (Internal Events x 5.9)	5.24E-08	1.80E-07	2.81E-07	2.29E-07
Combined (Internal + External)	**6.14E-08**	**2.11E-07**	**3.29E-07**	**2.68E-07**

Note to Table 5.7-5:

(1) Associated with the change from the baseline 3-per-10 year frequency to the proposed 1-per-15 year frequency.

The other metrics for the ILRT extension risk assessment can be similarly derived using the multiplier approach. The results between the 3-in-10 year interval and the 15 year interval compared to the acceptance criteria are shown in Table 5.7-6. As can be seen, the impact from including the external events contributors would not change the conclusion of the risk assessment. That is, the acceptance criteria are all met such that the estimated risk increase associated with permanently extending the ILRT surveillance interval to 15 years has been demonstrated to be small. Note that a bounding analysis for the total LERF contribution follows Table 5.7-6 to demonstrate that the total LERF value for HCGS is less than 1.0E-05/yr consistent with the requirements for a “Small Change” in risk of the RG 1.174 acceptance guidelines.

TABLE 5.7-6

COMPARISON TO ACCEPTANCE CRITERIA INCLUDING EXTERNAL EVENTS CONTRIBUTION FOR HCGS

CONTRIBUTOR	∆LERF	∆PERSON-REM/YR	∆CCFP[(1)]
Internal Events	3.91E-08	5.15E-03 (0.01%)	0.93%
External Events	2.29E-07	3.02E-02[(2)] (0.09%)	0.93%
Total	**2.68E-07**	**3.53E-02 (0.10%)**	**0.93%**
Acceptance Criteria	**<1.0E-6/yr ("small")**	**<1.0 person-rem/yr or <1.0%**	**<1.5%**

Notes to Table 5.7-6:

(1) The probability of leakage due to the ILRT extension is assumed to be the same for both Internal and External events. Therefore, the percentage change for CCFP remains constant.

(2) Calculated as the FPIE value times the external events multiplier of 5.9 developed in Table 5.7-4.

The 2.68E-07/yr increase in LERF due to the combined internal and external events from extending the ILRT frequency from 3-per-10 years to 1-per-15 years falls within Region II between 1.0E-7 to 1.0E-6 per reactor year ("small" change in risk) of the RG 1.174 acceptance guidelines. Per RG 1.174, when the calculated increase in LERF due to the proposed plant change is in the "small" change range, the risk assessment must also reasonably show that the total LERF is less than 1.0E-5/yr. Similar bounding assumptions regarding the external event contributions that were made above are used for the total LERF estimate.

From Table 4.2-2, the LERF (High Early) due to postulated internal event accidents is 8.45E-07/yr for HCGS. As discussed in Sections 5.7.1 and shown in Table 5.7-3, the LERF for the Fire PRA model is 3.08E-06 /yr. As discussed in Sections 5.7.2 and shown in Table 5.7-3, the total LERF estimate for the Seismic PRA model is 5.63E-07 /yr. The total LERF values for HCGS are shown in Table 5.7-7.

TABLE 5.7-7

IMPACT OF 15-YR ILRT EXTENSION ON LERF FOR HCGS

LERF CONTRIBUTOR	(1/YR)
Internal Events LERF	8.45E-07
Fire LERF	3.08E-06
Seismic LERF	5.63E-07
Internal Events LERF due to ILRT (at 15 years) (1)	4.80E-08
External Events LERF due to ILRT (at 15 years) (1)	2.81E-07 [Internal Events LERF due to ILRT * 5.9]
Total	**8.17E-06/yr**
Acceptance Criteria	**<1E-05/yr**

Note to Table 5.7-7:

(1) Including age adjusted steel liner corrosion likelihood as reported in Table 5.7-5.

As can be seen, the estimated upper bound LERF for HCGS is estimated as 8.17E-06/yr. This value is less than the RG 1.174 requirement to demonstrate that the total LERF due to internal and external events is less than 1.0E-05/yr.

5.8 CONTAINMENT OVERPRESSURE IMPACTS ON CDF

As indicated in the EPRI ILRT report [3], in general, CDF is not significantly impacted by an extension of the ILRT interval. However, plants that rely on containment overpressure for net positive suction head (NPSH) for emergency core coolant system (ECCS) injection for certain accident sequences may experience an increase in CDF.

For HCGS, there no dependency on containment overpressure for NPSH. The implementation of containment overpressure at HCGS has been assessed and it is found that the available NPSH exceeds the required NPSH even when the pool is saturated. See the HCGS Event Tree notebook for additional discussion [35].

6.0 SENSITIVITIES

6.1 SENSITIVITY TO CORROSION IMPACT ASSUMPTIONS

The results in Tables 5.2-2, 5.3-1, and 5.3-2 show that including corrosion effects calculated using the assumptions described in Section 4.4 does not significantly affect the results of the ILRT extension risk assessment. In any event, sensitivity cases were developed to gain an understanding of the sensitivity of the results to the key parameters in the corrosion risk analysis. The time for the flaw likelihood to double was adjusted from every five years to every two and every ten years. The failure probabilities for the wall and basemat were increased and decreased by an order of magnitude. The total detection failure likelihood was adjusted from 10% to 15% and 5%. The results are presented in Table 6.1-1. In every case, the impact from including the corrosion effects is minimal. Even the upper bound estimates with conservative assumptions for all of the key parameters yield increases in LERF due to corrosion of only 1.40E-07/yr. The results indicate that even with conservative assumptions, the conclusions from the base analysis would not significantly change.

TABLE 6.1-1

STEEL LINER CORROSION SENSITIVITY CASES FOR HCGS

AGE (STEP 3 IN THE CORROSION ANALYSIS)	CONTAINMENT BREACH (STEP 4 IN THE CORROSION ANALYSIS)	VISUAL INSPECTION & NON-VISUAL FLAWS (STEP 5 IN THE CORROSION ANALYSIS)	INCREASE IN CLASS 3B FREQUENCY (LERF) FOR ILRT EXTENSION FROM 3 IN 10 TO 1 IN 15 YEARS (PER YEAR)	
			TOTAL INCREASE	INCREASE DUE TO CORROSION
Base Case Doubles every 5 yrs	Base Case (10% Wall, 1% Basemat)	Base Case (10% Wall, 100% Basemat)	3.91E-08	4.85E-09
Doubles every 2 yrs	Base	Base	4.53E-08	1.11E-08
Doubles every 10 yrs	Base	Base	3.83E-08	4.09E-09
Base	Base	15% Wall	4.07E-08	6.46E-09
Base	Base	5% Wall	3.74E-08	3.23E-09
Base	100% Wall, 10% Basemat	Base	8.27E-08	4.85E-08
Base	1.0% Wall, 0.1% Basemat	Base	3.47E-08	4.85E-10
LOWER BOUND				
Doubles every 10 yrs	1.0% Wall, 0.1% Basemat	5% Wall, 100% Basemat	3.45E-08	2.72E-10
UPPER BOUND				
Doubles every 2 yrs	100% Wall, 10% Basemat	15% Wall, 100% Basemat	1.82E-07	1.48E-07

6.2 EPRI EXPERT ELICITATION SENSITIVITY

An expert elicitation was performed by EPRI [3] to reduce excess conservatisms in the data associated with the probability of undetected leaks within containment. Since the risk impact assessment of the extensions to the ILRT interval is sensitive to both the probability of the leakage as well as the magnitude, it was decided to perform the expert elicitation in a manner to solicit the probability of leakage as a function of leakage magnitude. In addition, the elicitation was performed for a range of failure modes which allowed experts to account for the range of failure mechanisms, the potential for undiscovered mechanisms, inaccessible areas of the containment as well as the potential for detection by alternate means. The expert elicitation process has the advantage of considering the available data for small leakage events, which have

occurred in the data, and extrapolate those events and probabilities of occurrence to the potential for large magnitude leakage events.

The basic difference in the application of the ILRT interval methodology using the expert elicitation is a change in the probability of pre-existing leakage within containment. The base case methodology uses the Jeffrey's non-informative prior for the large leak size and the expert elicitation sensitivity study uses the results from the expert elicitation. In addition, given the relationship between leakage magnitude and probability, larger leakage that is more representative of large early release frequency can be reflected. For the purposes of this sensitivity, the same leakage magnitudes that are used in the base case methodology (i.e., 10 L_a for small and 100 L_a for large) are used here. Table 6.2-1 illustrates the magnitudes and probabilities of a pre-existing leak in containment associated with the base case and the expert elicitation statistical treatments. These values are used in the ILRT interval extension for the base methodology and in this sensitivity case. Details of the expert elicitation process, including the input to expert elicitation as well as the results of the expert elicitation, are available in the various appendices of EPRI 1018243 [3].

TABLE 6.2-1

EPRI EXPERT ELICITATION RESULTS

LEAKAGE SIZE (L_a)	BASE CASE MEAN PROBABILITY OF OCCURRENCE	EXPERT ELICITATION MEAN PROBABILITY OF OCCURRENCE [3]	PERCENT REDUCTION
10	9.2E-03	3.88E-03	58%
100	2.3E-03	2.47E-04	89%

The summary of results using the expert elicitation values for probability of containment leakage is provided in Table 6.2-2. As mentioned previously, probability values are those associated with the magnitude of the leakage used in the base case evaluation (10 L_a for small and 100 L_a for large). The expert elicitation process produces a relationship between probability and leakage magnitude in which it is possible to assess

higher leakage magnitudes that are more reflective of large early releases; however, these evaluations are not performed in this particular study.

The net effect is that the reduction in the multipliers shown above also leads to a dramatic reduction on the calculated increases in the LERF values. As shown in Table 6.2-2, the increase in the overall value for LERF due to Class 3b sequences that is due to increasing the ILRT test interval from 3 to 15 years is just 8.52E-09/yr. Similarly, the increase due to increasing the interval from 10 to 15 years is just 4.51E-09/yr. As such, if the expert elicitation probabilities of occurrence are used instead of the non-informative prior estimates, the change in LERF is well within the range of a “very small” change in risk when compared to the current 1-in-10, or baseline 3-in-10 year requirement. Additionally, as shown in Table 6.2-2, the increase in dose rate and CCFP are similarly reduced to much smaller values. The results of this sensitivity study are judged to be more indicative of the actual risk associated with the ILRT extension than the results from the assessment as dictated by the values from the EPRI methodology [3], and yet are still conservative given the assumption that all of the Class 3b contribution is considered to be LERF.

TABLE 6.2-2

HCGS ILRT CASES: 3 IN 10 (BASE CASE), 1 IN 10, AND 1 IN 15 YR INTERVALS (BASED ON EPRI EXPERT ELICITATION LEAKAGE PROBABILITIES)

<table>
<tr><th rowspan="2" colspan="2">EPRI CLASS</th><th rowspan="2">DOSE PER-REM</th><th colspan="2">BASE CASE 3 IN 10 YEARS</th><th colspan="2">EXTEND TO 1 IN 10 YEARS</th><th colspan="2">EXTEND TO 1 IN 15 YEARS</th></tr>
<tr><th>CDF (1/YR)</th><th>PERSON-REM/YR</th><th>CDF (1/YR)</th><th>PERSON-REM/YR</th><th>CDF (1/YR)</th><th>PERSON-REM/YR</th></tr>
<tr><td colspan="2">1</td><td>1.01E+03</td><td>1.20E-06</td><td>1.21E-03</td><td>1.16E-06</td><td>1.17E-03</td><td>1.13E-06</td><td>1.14E-03</td></tr>
<tr><td colspan="2">2</td><td>2.34E+07</td><td>3.23E-07</td><td>7.56E+00</td><td>3.23E-07</td><td>7.56E+00</td><td>3.23E-07</td><td>7.56E+00</td></tr>
<tr><td colspan="2">3a</td><td>1.01E+04</td><td>1.44E-08</td><td>1.46E-04</td><td>4.80E-08</td><td>4.85E-04</td><td>7.21E-08</td><td>7.28E-04</td></tr>
<tr><td colspan="2">3b</td><td>1.01E+05</td><td>1.31E-09</td><td>1.33E-04</td><td>5.32E-09</td><td>5.38E-04</td><td>9.83E-09</td><td>9.93E-04</td></tr>
<tr><td colspan="2">7</td><td>9.20E+06</td><td>2.50E-06</td><td>2.30E+01</td><td>2.50E-06</td><td>2.30E+01</td><td>2.50E-06</td><td>2.30E+01</td></tr>
<tr><td colspan="2">8</td><td>2.34E+07</td><td>1.69E-07</td><td>3.95E+00</td><td>1.69E-07</td><td>3.95E+00</td><td>1.69E-07</td><td>3.95E+00</td></tr>
<tr><td colspan="2">Total</td><td></td><td>4.21E-06</td><td>34.563</td><td>4.21E-06</td><td>34.564</td><td>4.21E-06</td><td>34.564</td></tr>
<tr><td colspan="9"></td></tr>
<tr><td colspan="3">ILRT Dose Rate from 3a and 3b</td><td colspan="2">2.78E-04</td><td colspan="2">1.02E-03</td><td colspan="2">1.72E-03</td></tr>
<tr><td rowspan="2">Delta Total Dose Rate[1]</td><td colspan="2">From 3 yr</td><td colspan="2">---</td><td colspan="2">7.06E-04</td><td colspan="2">1.38E-03</td></tr>
<tr><td colspan="2">From 10 yr</td><td colspan="2">---</td><td colspan="2">---</td><td colspan="2">6.70E-04</td></tr>
<tr><td colspan="9"></td></tr>
<tr><td colspan="3">3b Frequency (LERF)</td><td colspan="2">1.31E-09</td><td colspan="2">5.32E-09</td><td colspan="2">9.83E-09</td></tr>
<tr><td rowspan="2">Delta 3b LERF</td><td colspan="2">From 3 yr</td><td colspan="2">---</td><td colspan="2">4.01E-09</td><td colspan="2">8.52E-09</td></tr>
<tr><td colspan="2">From 10 yr</td><td colspan="2">---</td><td colspan="2">---</td><td colspan="2">4.51E-09</td></tr>
<tr><td colspan="9"></td></tr>
<tr><td colspan="3">CCFP %</td><td colspan="2">71.21%</td><td colspan="2">71.31%</td><td colspan="2">71.41%</td></tr>
<tr><td rowspan="2">Delta CCFP %</td><td colspan="2">From 3 yr</td><td colspan="2">---</td><td colspan="2">0.10%</td><td colspan="2">0.20%</td></tr>
<tr><td colspan="2">From 10 yr</td><td colspan="2">---</td><td colspan="2">---</td><td colspan="2">0.11%</td></tr>
</table>

Note to Table 6.2-2:

[1] The overall difference in total dose rate is less than the difference of only the 3a and 3b categories between two testing intervals. This is due to the fact that the Class 1 person-rem/yr decreases when extending the ILRT frequency.

7.0 CONCLUSIONS

Based on the results from Section 5.0 and the sensitivity calculations presented in Section 6.0, the following conclusions regarding the assessment of the plant risk are associated with permanently extending the Type A ILRT test frequency to fifteen years:

- Reg. Guide 1.174 [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 1.0E-06/yr and increases in LERF below 1.0E-07/yr. "Small" changes in risk are defined as increases in CDF below 1.0E-05/yr and increases in LERF below 1.0E-06/yr. Since the ILRT extension was demonstrated to have negligible impact on CDF for HCGS, the relevant criterion is LERF. The increase in internal events LERF resulting from a change in the Type A ILRT test interval for the base case with corrosion included is 3.91E-08/yr (see Table 5.6-1). In using the EPRI Expert Elicitation methodology, the change is estimated as 8.52E-09/yr (see Table 6.2-2). Both of these values fall within the "very small" change region of the acceptance guidelines in Reg. Guide 1.174.
- The change in dose risk for changing the Type A test frequency from three-per-ten years to once-per-fifteen-years, measured as an increase to the total integrated dose risk for all internal events accident sequences for HCGS, is 5.15E-03 person-rem/yr (0.01%) using the EPRI guidance with the base case corrosion included (Table 5.6-1). The change in dose risk drops to 1.38E-03 person-rem/yr (<0.01%) when using the EPRI Expert Elicitation methodology (Table 6.2-2). The values calculated per the EPRI guidance are all lower than the acceptance criteria of ≤1.0 person-rem/yr or <1.0% person-rem/yr defined in Section 1.3.
- The increase in the conditional containment failure frequency from the three in ten year interval to one in fifteen years including corrosion effects using the EPRI guidance (see Section 5.5) is 0.93%. This value drops to 0.20% using the EPRI Expert Elicitation methodology (see Table 6.2-2). Both of these values are below the acceptance criteria of less than 1.5% defined in Section 1.3.
- To determine the potential impact from external events, a bounding assessment from the risk associated with external events was performed utilizing available information. As shown in Table 5.7-6, the total increase in LERF due to internal events and the bounding external events assessment is 2.68E-07/yr. This value is in Region II of the Reg. Guide 1.174 acceptance guidelines ("small" change in risk). The changes in dose risk and conditional containment failure frequency also remained below the acceptance criteria.

- As shown in Table 5.7-7, the same bounding analysis indicates that the total LERF from both internal and external risks is 8.17E-06/yr which is less than the Reg. Guide 1.174 limit of 1.0E-05/yr given that the ΔLERF is in Region II ("small" change in risk).
- Including age-adjusted steel liner corrosion effects in the ILRT assessment was demonstrated to be a small contributor to the impact of extending the ILRT interval for HCGS.

Therefore, 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 HCGS risk profiles.

Previous Assessments

The NRC in NUREG-1493 [6] has previously concluded the following:

- Reducing the frequency of Type A tests (ILRTs) from three per 10 years to one per 20 years was found to lead to an imperceptible increase in risk. The estimated increase in risk is very small because ILRTs identify only a few potential containment leakage paths that cannot be identified by Type B and C testing, and the leaks that have been found by Type A tests have been only marginally above existing requirements.
- Given the insensitivity of risk to containment leakage rate and the small fraction of leakage paths detected solely by Type A testing, increasing the interval between integrated leakage-rate tests is possible with minimal impact on public risk. The impact of relaxing the ILRT frequency beyond one in 20 years has not been evaluated. Beyond testing the performance of containment penetrations, ILRTs also test the integrity of the containment structure.

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

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APPENDIX A
PRA TECHNICAL ADEQUACY

A.1 OVERVIEW

A technical Probabilistic Risk Assessment (PRA) analysis is presented in this report to help support an extension of the HCGS containment Type A test integrated leak rate test (ILRT) interval to fifteen years.

The analysis follows the guidance provided in Regulatory Guide 1.200, Revision 2 [A.1], "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities." The guidance in RG 1.200 indicates that the following steps should be followed to perform this study:

1. Identify the parts of the PRA used to support the application
   - SSCs, operational characteristics affected by the application and how these are implemented in the PRA model.
   - A definition of the acceptance criteria used for the application.
2. Identify the scope of risk contributors addressed by the PRA model
   - If not full scope (i.e. internal and external), identify appropriate compensatory measures or provide bounding arguments to address the risk contributors not addressed by the model.
3. Summarize the risk assessment methodology used to assess the risk of the application
   - Include how the PRA model was modified to appropriately model the risk impact of the change request.
4. 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 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 Regulatory Guide. 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.

Items 1 through 3 are covered in the main body of this report. The purpose of this appendix is to address the requirements identified in item 4 above. Each of these items (plant changes not yet incorporated into the PRA model, relevant peer review findings, consistency with applicable PRA standards and the identification of key assumptions) are discussed in the following sections.

The risk assessment performed for the ILRT extension request is based on the current Level 1 and Level 2 PRA model. Note that for this application, the accepted methodology involves a bounding approach to estimate the change in the LERF from extending the ILRT interval. Rather than exercising the PRA model itself, it involves the establishment of separate evaluations that are linearly related to the plant CDF contribution. Consequently, a reasonable representation of the plant CDF that does not result in a LERF does not require that Capability Category II be met in every aspect of the modeling if the Category I treatment is conservative or otherwise does not significantly impact the results.

A discussion of the PSEG model update process, the peer reviews performed on the HCGS models, the results of those peer reviews and the potential impact of peer review findings on the ILRT extension risk assessment are provided in Section A.2. Section A.3 provides an assessment of key assumptions and approximations used in this assessment. Finally, Section A.4 briefly summarizes the results of the PRA technical adequacy assessment with respect to this application.

A.2 PRA MODEL EVOLUTION AND PEER REVIEW SUMMARY

A.2.1 Introduction

The HC111A version of the HCGS PRA model is the most recent evaluation of the risk profile at HCGS for internal event challenges. The HCGS 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 HCGS PRA is based on the event tree / fault tree methodology, which is a well-known methodology in the industry.

PSEG employs a multi-faceted approach to establishing and maintaining the technical adequacy and plant fidelity of the PRA models for all operating PSEG nuclear generation sites. This approach includes both a proceduralized PRA maintenance and update process, and the use of self-assessments and independent peer reviews. The following information describes this approach as it applies to the HCGS PRA.

A.2.2 PRA Maintenance and Update

The PSEG risk management process ensures that the applicable PRA model is an accurate reflection of the as-built and as-operated plants. This process is defined in the PSEG Risk Management program, which consists of a governing procedure and subordinate implementation procedures. The PRA model update procedure delineates the responsibilities and guidelines for updating the full power internal events PRA models at all operating PSEG nuclear generation sites. The overall PSEG Risk Management program defines the process for implementing regularly scheduled and interim PRA model updates, for tracking issues identified as potentially affecting the PRA models (e.g., due to changes in the plant, industry operating experience, etc.), and for controlling the model and associated computer files. To ensure that the current PRA model remains an accurate reflection of the as-built, as-operated plants, the following activities are routinely performed:

- Design changes and procedure changes are reviewed for their impact on the PRA model.
- Plant specific initiating event frequencies, failure rates, and maintenance unavailabilities are updated approximately every four years.

In addition to these activities, PSEG risk management procedures provide the guidance for particular risk management maintenance activities. This guidance includes:

- Documentation of the PRA model, PRA products, and bases documents.

- The approach for controlling electronic storage of Risk Management (RM) products including PRA update information, PRA models, and PRA applications.
- Guidelines for updating the full power, internal events PRA models for PSEG nuclear generation sites.
- Guidance for use of quantitative and qualitative risk models in support of the On-Line 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 (10 CFR 50.65(a)(4)).

In accordance with this guidance, regularly scheduled PRA model updates nominally occur on an approximately 4-year cycle; longer intervals may be justified if it can be shown that the PRA continues to adequately represent the as-built, as-operated plant. The HC111A models were completed in December of 2011. An analysis that evaluated plant modifications and procedure changes since 2011, all other Update Requirements Evaluations (UREs) and changing industry data was completed in 2015 concluded that the HCGS PRA continues to represent adequately the as-built, as-operated plant.

As indicated previously, RG 1.200 also requires that additional information be provided as part of the LAR submittal to demonstrate the technical adequacy of the PRA model used for the risk assessment. Each of these items (plant changes not yet incorporated into the PRA model, relevant peer review findings, and consistency with applicable PRA Standards) will be discussed in turn in this section.

A.2.3 Plant Changes Not Yet Incorporated into the PRA Model

A PRA updating requirements evaluation (URE- HCGS PRA model update tracking database) is created for all issues that are identified that could impact the PRA model. The URE database includes the identification of those plant changes that could impact the PRA model.

A review of the open UREs indicates that there are no plant changes that have not yet been incorporated into the PRA model that would affect this application.

A.2.4 Consistency with Applicable PRA Standards

Several assessments of technical capability have been made for the HCGS internal events PRA models. These assessments are as follows and are further discussed in the paragraphs below.

- An independent PRA peer review [A.7] was conducted under the auspices of the BWR Owners Group in 2009, following the Industry PRA Peer Review process [A.2]. This peer review included an assessment of the PRA model maintenance and update process.
- In January 2011, a self-assessment was performed against the available version of the ASME/ANS PRA Standard [A.6] in preparation for the HCGS 2011 PRA periodic update.

The HCGS PRA has previously undergone a thorough PRA Peer Review consistent with the NEI PRA Peer Review Guidelines (NEI 00-02 [A.12]). The results of that PRA Peer Review found that the PRA was capable of being used for risk-informed applications. The Capability Category and Findings and Suggestions results derived from the HCGS PRA Peer Review(1) were as follows:

- Capability Category
  - 96% of the Supporting Requirements were Capability Category II or III
  - 2% of the Supporting Requirements were CCI
  - 2% of the Supporting Requirements were Not Met
- Facts and Observations
  - Findings: There were 15 Findings
  - Suggestions: There were 63 Suggestions

This PRA Peer Review was used as an initial input into the PRA Self-Assessments relative to the combined ASME/ANS PRA Standard. There were 326 technical

(1) The NEI 00-02 [A.12] grading scheme differs from that found in the ASME/ANS PRA Standard [1].

Supporting Requirements that were evaluated as part of the HC111A PRA related self-assessments. Of these 326 Supporting Requirements, the documentation and the model were judged to meet the ASME/ANS PRA Standard to support Capability Category II for all 326.

After the HC111A HCGS PRA update, the assessment of the PRA indicated the following results:

Number of Supporting Requirements at Capability Category II or higher or Deemed Not Applicable	326 of 326
Number of Gaps Identified for HC111A PRA (Capability Category at I or Not Met)	0

The HCGS model has no gaps identified as part of the self-assessment process.

The HCGS HC111A PRA model is the result of updating the HCGS PRA model. As indicated above, a PRA model update was completed in 2011, resulting in the HC111A updated model. The PRA model assessments show that 100% of all the supporting requirements are characterized as meeting Capability Category II or better and all of the applicable Findings and Observations have been addressed.

A.2.5 Applicability of Peer Review Findings and Observations

Per the NRC SE [7] the appropriate PRA quality to support an ILRT risk assessment is that the PRA Standard Supporting Requirements should meet Capability Category I or greater. There are 316 Technical Supporting Requirements plus 10 Maintenance and Update Supporting Requirements in the FPIE portion of the ASME/ANS PRA Standard [A.6].

Per the latest HCGS PRA Self-Assessment [A.10], there are no Supporting Requirements that are not met or addressed.

Table A-1 provides a summary of the HCGS F&Os from the Peer Review. , Table A-1 identified no outstanding “gaps” to meeting Capability Category II of the ASME/ANS PRA Standard [A.6] and RG 1.200, Rev. 2 [A.1]. As detailed in Table A-1, no “gaps” fundamentally impact the conclusions of this ILRT extension application.

TABLE A-1

RESOLUTION OF PEER REVIEW F&Os

F&O	F&O DESCRIPTION	RESOLUTION
F&O DA-D1-01 Expand use of Plant specific reliability data	Plant specific data was not collected for the most recent update reliability data. The only plant specific information used was for systems that are monitored by the MSPI program. MSPI systems include the diesel generators, HPCI, RCIC, RHR, SSWS and SACS. No other specific data was used for this update. Individual component random failure data is a vital input to the PSA. Therefore, special attention is paid to ensuring that the best available information is used as input to the PSA. FINDING - As outlined in the Component Data Notebook, "individual component random failure data is a vital input to the PSA. Therefore, special attention is paid to ensuring that the best available information is used as input to the PSA." Inadequate data collection and update could have an actual impact on the accuracy of the PRA.	Plant-specific data request forms were sent to each of the system managers for their input. Plant-specific data was used where appropriate for the HC 2011 PRA update.
F&O HR-D3-01 Documentation regarding the quality of written procedures	No documented evidence was seen that the quality of procedures, administrative controls or human-machine interface were evaluated for the pre-initiator HEPs, nor of the impact of that quality on the HEP evaluation. FINDING - Need to consider the above mentioned items to meet Capability Category 2.	The quality of the Hope Creek procedures and the human-machine interface were both evaluated as part of the pre-initiator HEP assessment. Both of these aspects were found by the HRA analysts to be above the quality level typically found for BWRs. Sections 3.0.4 and 3.0.13 of the HRA Notebook explicitly address this issue and are used to establish and document the basis for assessing the quality of the PSEG and HCGS procedural guidance. There is no requirement to document the quality of the procedures or the human-machine interface. If there were an SR it would be listed under HR-I.
F&O HR-C2-01 Additional restoration error (e.g. power supply to specific components)	Tables 4.3-4 and 4.3-5 of the HR Notebook (HC PSA-004, Rev. 0) present the defined restoration and miscalibration Type A HFEs. Additional information provided by PSEG regarding additional errors (e.g., restoration of power supply) referred only to the ACP events in Tables 4.3-4 and 4.3-5. However, these pertain only to bus voltage sensors for undervoltage transfers and restoration of the gas turbine. FINDING - This issue must be addressed to include all of	The requested actions were screened from consideration using HR-B1, and therefore, are not applicable for HR-C1.

TABLE A-1

RESOLUTION OF PEER REVIEW F&Os

F&O	F&O DESCRIPTION	RESOLUTION
	the modes of unavailability specified for Category II in this SR.	
F&O IE-A6-01 Additional interview documentation expected	Section 2.1 of the IE notebook (HC PSA-001, Rev 1) notes that interviews were conducted with operations and engineering personnel for precursors, possible plant-unique IEs, and confirmation of the IEs derived from the master logic diagram. However, there is no documentation or detailed reference in the IE notebook on these interviews. Appendix I is referenced regarding the precursors, but there are no details on interviews within that appendix. The HRA notebook is also mentioned, although Section 2.6 and Appendix F describe only interviews regarding the EOPs, PSFs, training, response time, etc.; where it was noted that the loss of a single 7.2kV bus does not cause a Reactor Scram based on operations interviews (February 2003). Finally, the system notebooks are also mentioned, but a review of the interview documentation in the AC and SSW notebooks shows essentially a duplication of the IE assessment included in the IE notebook, there is no indication of any insights, clarifications, or confirmations provided by the system manager.	The Initiating Event Notebook documents the results of the systematic process for determining initiating events including the results of both interview processes. Finally, subsequent to the Peer Review in October 2008 the documentation of the System Manager interviews in the System Notebooks has been reviewed by the System Managers and they have signed these interview summaries as accurately reflecting the interviews.
F&O IE-A4-01 - System initiator analysis detail	Section 2.4.12 of the IE notebook (HC PSA-001, Rev 1) presents the evaluation of potential special initiators (SIs) that result in trip or shutdown and degrade a mitigating or support system. Each plant system is listed in Table 2.4-0, but no qualitative review or structured evaluation of impacts is provided as to why a system was or was not screened as a SI. Subsequent evaluation of those systems designated as SI considers the systems on a train basis. For some systems (SSW, SACS, PCIG, some HVAC, etc.) loss of the system or a single loop or train is screened out per criterion (c) in SR IE-C4 although no supporting calculations are referenced showing there is sufficient time to detect and correct the IE conditions before normal plant operation is	The discussion in the finding indicates the following: For some systems (SSW, SACS, PCIG, some HVAC, etc.) loss of the system or a single loop or train is screened out per criterion (c) in SR IE-C4 However, the HCGS PRA explicitly models the initiators associated with the following: Loss of SSW %IE-SWS Loss of SACS %IE-SACS Loss of PCIG %IE-IAS

TABLE A-1

RESOLUTION OF PEER REVIEW F&Os

F&O	F&O DESCRIPTION	RESOLUTION
	curtailed. For other systems (AC and DC power) no consideration is given to failures of lower bus, MCC or panels.	(See Initiating Event Notebook Section 4.) The loss of HVAC is explicitly screened out using the screening criterion IE-C4(c). The basis for this is the room heat up calculations provided in the Dependency Notebook which show the times to heat up critical areas is tens of hours and proceduralized guidance is available for alternate cooling. Therefore, the IE-C4(c) screening criteria is met for the HVAC initiator and the other cited initiators are not screened out. B. For lower voltage buses, MCCs, or panels, these failures are subsumed into the higher voltage or the bus with higher impacts. The special initiator list has been compared with other comparable BWRs, and there is no evidence that any Special Initiators (SI) were missed. The discussion seems to only look for a more detailed documentation of the basis for exclusion and the process used. A suggestion would appear to be a more appropriate category.
F&O SY-A2-01 (SY-A4 is Not Met) Plant Walkdown and Interview documentation	The interview seems to be a replication of the previous text of the system notebook. There is no evidence of feedback from the interviewee. The walkdowns are to confirm that the systems analysis is correct. The results of the system walkdowns are merely summed up as being captured in the system evaluation models. This does not meet the intent of the walkdowns.	The operator interviews are 1 of 14 example items in this SR. The operators were interviewed to ascertain both sequence related responses and system specific manipulation. These insights are recorded in the Appendix F of the HRA Notebook. There is not a requirement to highlight the changes to the System Notebooks based on the System Manager Interviews. There is not a requirement to document the system walkdowns. This would be a documentation SR if there was to be a requirement and would appear under SY-C. Even the interviews are only examples of types of

TABLE A-1

RESOLUTION OF PEER REVIEW F&Os

F&O	F&O DESCRIPTION	RESOLUTION
		information to be gathered. The Internal Flood Walkdown Notebook is the most recent documented PRA walkdown and it addresses the spatial influences that may affect systems (primarily flood related). However, walkdowns are not identified as an "example" of the information to be gathered by ASME SR SY-A2. As noted, operator interviews specifically related to systems is an example technique, not a requirement of the ASME PRA Standard. Subsequent to the Peer Review, the System Managers that were interviewed were requested to review the System Notebooks and interview results. They confirmed the findings of the interviews by signing the System Notebook Interview sheets.
F&O IF-D5-01 Service Water Frequency not match EPRI value	The Service Water failure frequencies should match the EPRI failure guideline but they don't. The frequency used is less conservative than that provided in the EPRI guidance. Table G-1 needs to be updated to reflect the correct Service Water (river) rupture frequencies. Note an incorrect rupture frequency was used for the Service Water (river) calculations. This will require the calculations for those sections to be re-performed using the correct EPRI failure frequency. FINDING - This is designated a finding as the wrong frequencies were used for SW failures, which will require correction and update of the calculations.	The PRA Peer Review finding for the pipe rupture frequency was incorporated into the HC108B PRA model. The small change in pipe rupture frequency resulted in a very small change in the CDF and LERF risk metrics. This finding has now been resolved and incorporated in the documentation and the updated PRA model. This represents a single example of possible slight deviation from the most current generic data. It does not represent "a systematic failure to address the requirement" as noted in the R.G. 1.200 guidance on the treatment of omissions or oversight. Therefore, it would appear appropriate to classify this as a Suggestion.
F&O LE-G1-01 Level 2 Analysis roadmap detail enhancement	The Level 2 Analysis Notebook (HC PSA-015, Rev. 0) was very detailed, but was not written in a manner conducive to demonstrating the requirements of the standard were met. The documentation roadmap (HC PSA-00, Rev. 0) for the Supporting Requirements for LERF was not helpful in locating information within the Level 2 notebook and in some cases incorrect.	The PRA documentation Roadmap Document contains the requested specific Level 2 references for each of the Supporting Requirements. Attached is the Roadmap for the Level 2 cross references to the ASME PRA Standard SRs. This same structure for the Level 2 has been subject to

TABLE A-1

RESOLUTION OF PEER REVIEW F&Os

F&O	F&O DESCRIPTION	RESOLUTION
	FINDING - The lack of cross-reference, or organization according to, the PRA standard for the LERF analysis limited the ability of the Peer Review team to perform an adequate review.	ASME PRA Standard Peer Reviews for NMP1, Oyster Creek, Cooper, Browns Ferry, and Limerick. In addition, this structure has also been Peer Reviewed using the NEI 00-02 process for Quad Cities, Dresden, LaSalle, and Peach Bottom. In none of these Peer Reviews has there been any suggestion or finding that indicates that the documentation is not straightforward and easily interpreted with respect to the requirements. Additional specificity added to the Roadmap Document following the Peer Review to even further enhance the traceability between the ASME PRA Standard SRs and the documentation.
F&O QU-F6-01 Addition of significance definition in Summary NB	Per the 2008 Self-Assessment and Roadmap Hope Creek states that they adopted the ASME Definitions for significant BE, cutset, and accident sequences. However, this does not appear to be documented anywhere. The HCGS Quantification notebook (HC PSA-014, Rev. 1) and the PRA Summary notebook (HC PSA-013, Rev. 0) do not appear to include the quantitative definition for significant basic event, significant cutset, and significant accident sequence from Section 2 of the ASME PRA Standard, nor justify an alternative. In addition, the presentation of "significant" results (cutsets, accident sequences, and basis events) clearly does not follow the definitions from the ASME PRA Standard.	It is noted that this observation has been implemented in HC108B model of 12/30/08. The documentation of this definition is added to the Section 2 of the HC108B PRA Summary Document.
F&O QU-F3-01 Failure to discuss top 95% accident sequences	Section 6.0 of the HCGS Quantification notebook (HC PSA-014, Rev. 1) and Section 3 of the PRA Summary notebook (HC PSA-013, Rev. 0) present some of the significant contributors, including initiating events (Tables 6.2-4 and 3.2-4) and accident sequence subclass (Tables 6.2-5 and 3.2-5). Appendix F of the Quantification notebook also provides overall event importance measures, for what appears to include all significant events. Section 6.3 discusses the top 10 accident	The ASME PRA Standard directions for Capability Category II state: "DOCUMENT the significant contributors ('such as'(1) initiating events, accident sequences, basic events) to CDF in the PRA results summary. PROVIDE a detailed description of significant accident sequences or functional failure groups." The significant contributors listed are examples. The

TABLE A-1

RESOLUTION OF PEER REVIEW F&Os

F&O	F&O DESCRIPTION	RESOLUTION
	sequences (68% of the total CDF and at least 2.5% individually) Per the ASME standard, significant accident sequences are those that combine to represent 95% of the CDF or individually represent 1% of the overall CDF. However, there is not a detailed discussion of the significant accident sequences, and the summary table of Accident Classes does not provide a detailed description of significant functional failure groups and does not provide a full, clear picture of the combinations of system or functional failures to which the plant is vulnerable and why they are significant; which is required to distinguish CC II from CCI. FINIDING - The information provided is incomplete such that the Cat II SR is not met.	contributing basic events including initiators, HEPs, common cause, and equipment failures are documented in the importance listing of the basic events. The second sentence from this SR requires a detailed description of the significant accident sequences or functional failure groups. The choice for the HCGS PRA is to describe the functional failure groups, i.e., the accident classes. These accident classes (functional failure groups) are described and graphically displayed in the Quantification Notebook and the PRA Summary Notebook. Therefore, PSEG believes that the requirements are met. The insight to expand the discussion of accident sequences to include more sequences is a good one and will be pursued in 2009. However, this is not considered a failure to meet an ASME Requirement. This would have no impact on the ILRT extension analysis.
F&O QU-E4-01 Uncertainty analysis structured sensitivity evaluations	Section 3.4 and Appendix B and C of the PRA Summary notebook (HC PSA-013) provide an evaluation of the important model uncertainties and Section 4.5 and Appendix E provide a set of structured sensitivity evaluations based on these uncertainties. Sensitivity calculations were run, with seven cases being identified as important to model uncertainty. Table 4.5-1 of the PSA-013 contains a summary of sensitivity cases to identify risk metric changes associated with candidate modeling uncertainties. The uncertainties are identified based on generic sources of uncertainty provided in EPRI TR-10009652. However, no additional plant-specific sources of uncertainty are addressed. Initial clarification on sources of uncertainty was provided in a July 27, 2007 NRC memorandum, which specified that at a minimum for a base PRA the analyst must "identify the assumptions	The resolution of the treatment of modeling uncertainties in the PRA base model and in applications has NOT yet been resolved. NUREG-1855 has not been issued and the ACRS has not yet agreed with an approach. Plant unique features of Hope Creek that affected the more general uncertainty categories were explicitly captured in the sensitivity evaluations using the Hope Creek model. Additional areas of the Hope Creek PRA were investigated for this potential impact on risk metrics, however, no additional areas rose to the level that they would be considered candidates for modeling uncertainty. The draft EPRI document referred to was not issued during the development of the HCGS PRA and is not considered to apply to the base PRA model and its

TABLE A-1

RESOLUTION OF PEER REVIEW F&Os

F&O	F&O DESCRIPTION	RESOLUTION
	related to PRA scope and level of detail, and characterize the sources of model uncertainty and related assumptions, i.e., identify what in the PRA model could be impacted and how". In addition, "While an evaluation of any source of model uncertainty or related assumption is not needed for the base PRA, the various sources of model uncertainty and related assumptions do need to be characterized so that they can be addressed in the context of an application. Therefore, the search for candidates needs to be fairly complete (regardless of capability category), because it is not known, a priori, which of the sources of model uncertainty or related assumptions could affect an application." So excluding plant-specific sources of uncertainty from characterization because they did not "rise to the level that they would be considered candidates for modeling uncertainty" is not appropriate. FINDING - The information provided is incomplete; the most recent industry guidance to address modeling uncertainty in order to meet Cat II for these SRs is not met.	documentation. In addition, NUREG-1855 may in the future require similar recommendations for applications, but not as part of the base PRA model and its documentation. The ASME PRA Standard does not currently require the recommended evaluation. This would have no impact on the ILRT extension analysis.
F&O QU-D5a-01 Significant SSCs and HR that contribute to initiating events	Section 6.0 of the HCGS Quantification notebook (HC PSA-014, Rev. 1) and Section 3 of the PRA Summary notebook (HC PSA-013, Rev. 0) present some of the significant contributors, including initiating events (Tables 6.2-4 and 3.2-4) and accident sequence subclass (Tables 6.2-5 and 3.2-5). Appendix F of the Quantification notebook also provides overall event importance measures. Although they are not categorized by initiating event, equipment failures, common cause failures or operator errors, they do appear to include all significant events. (Per the ASME standard, significant events are those that have a F-V importance greater than 0.005 or RAW importance greater than 2.) Similar information is provided for LERF. Section 4.2 of the Section 6.0 of the HCGS Quantification notebook (HC PSA-014, Rev. 1) and Section 3 of the PRA Summary notebook (HC PSA-013,	SSCs and operator actions involved in event mitigation are included in the importance rankings provided in the appendices. This satisfies the need to identify "significant" events. The Standard allows point estimates for IE values. Also, the importance of systems as mitigators is not affected by how they are described in initiating events. In addition, the support system initiators are evaluated as part of the importance assessment. Based on this importance evaluation, the operator actions contained in these IE can be assessed if needed. Therefore, the observation appears to fall into the realm of a Suggestion as opposed to a Finding. Possible Discrepancies between App. F and Section 4.3 of the Summary Notebook

TABLE A-1

RESOLUTION OF PEER REVIEW F&Os

F&O	F&O DESCRIPTION	RESOLUTION
	Rev. 0) present some of the significant contributors, including initiating events (Tables 6.2-4 and 3.2-4) and accident sequence subclass (Tables 6.2-5 and 3.2-5). Appendix F of the Quantification notebook also provides overall event importance measures. Although they are not categorized by initiating event, equipment failures, common cause failures or operator errors, they do appear to include all significant events. (Per the ASME standard, significant events are those that have a F-V importance greater than 0.005 or RAW importance greater than 2.) Similar information is provided for LERF. Section 4.2 of the Summary notebook provides risk rankings for system trains based on RAW, and Section 4.3 provides the risk important operator actions based on F-V . However, the identification of significant contributors does not include SSCs and operator actions that contribute to initiating event frequencies although those that contribute to event mitigation have been. Also ensure Summary notebook discussion matches results from QU notebook (e.g., risk important operator actions). FINDING - The information provided is incomplete such that the Cat II SR is not met.	The interpretation of the risk impact of basic events from a listing of importance measures is easily formulated by examining the probability, the FV Importance, and the RAW. From a consideration of the metrics and for the purpose of providing insights to the plant, those top five to ten HEPs that could be influenced by hardware, procedure, or training changes are highlighted in Section 4.3. Therefore, the listing of actions in Section 4.3 have distilled the raw results of the importance tables in Appendix F to provide the PRA analysts interpretation of risk important actions. The only actions not listed in Section 4.3 of the top 11 HEPs are those that are guaranteed successes or ones subsumed into other HEP events.
F&O SC-A6-01 Basis for the fire pump flow rate	The HCGS PRA basis for success criteria are consistent with the features, procedures, and operating philosophy of the plant, as documented in the Success Criteria notebook (HC PSA-003, Rev 0). However, for the diesel-driven fire-water pump the flow may be assumed too high. The basis for the fire pump as a low pressure source of makeup to the vessel after depressurization is based on flow rate inputs which lack rigor. The flow input to MAAP merely reduces the published pump curve by 20% to account for flow friction losses. The MAAP input also does not correct the pump curve for elevation difference between the fire pump water source and the injection point. Success of the fire pump as a low pressure source of makeup solely	A detailed PSEG deterministic calculation for the use of the FPS and a Fire Pumper Truck in tandem was used to confirm the FPS flow rate to the RPV. PSEG has developed two PSEG calculations to support operation of the Fire Water system to provide RPV injection. These include: - Calculation that uses the Diesel Fire Pump only. This calculation was input into the updated MAAP model. - Calculation that uses the on-site Fire Pumper Truck and the Diesel Fire Pump – PSEG Calc NC.DE-AP.ZZ-0002(Q), May 2002. The first PSEG calculation performed by the PRA group

TABLE A-1

RESOLUTION OF PEER REVIEW F&Os

F&O	F&O DESCRIPTION	RESOLUTION
	depends on its ability to provide adequate makeup. The fire pump flow rate should be based on a flow calculation that considers the piping and fire hose friction and elevation differences. FINDING: The fire pump flow rate should be based on a documented flow calculation that considers the piping and fire hose friction and elevation differences.	was used in the MAAP model development, it is contradicted by the other more detailed engineering calculation, NC.DE-AP.ZZ-0002 (Q). Using the updated PRA model and the more limiting PSEG calculation results in the following changes relative to the HC108A PRA model: - The Fire Truck is used to boost the discharge pressure from the DFP to achieve adequate injection head. - The fire water injection is dependent on the use of the Fire Pumper Truck for success. - The Fire Pumper Truck is not Tech Spec controlled equipment and could be unavailable. - The large recirc pump seal LOCA is not mitigated by the Fire Pumper Truck. The revised MAAP calculations to support this evaluation included sensitivity cases as follows: - HC07007x_A: ED with 5 SRVs at HCTL at 6.4 hr. RCIC tripped at 6.6 hr. Fire water is not able to fully recover level. TAF is reached at 7.5 hr. but level stabilizes at approximately -200" until SRVs reclose at 21 hr. at 50 psid and RPV pressure increases. As expected and accounted for in the model, without containment heat removal, CD results at 22.3 hr. - HC07007x_C: ED with 2 SRVs at HCTL at 6.4 hr. RCIC tripped at 7.1 hr. Fire water recovers level and level is at normal at 24 hr. SRVs reclose at 23 hr. As expected and accounted for in the model, without containment heat removal, CD results at 30.1 hr. A small recirculation seal leak is imposed during both of the event sequences. These sensitivity cases resulted in the conclusion that: HC07007x_A: Success for RPV injection; Containment Heat Removal is Required

TABLE A-1

RESOLUTION OF PEER REVIEW F&Os

F&O	F&O DESCRIPTION	RESOLUTION
		HC07007x_C: Success for RPV injection; Containment Heat Removal is Required RPV injection with the Fire Pumper Truck and the DFP pump provides adequate RPV injection for the SBO events for which late RPV injection at low pressure is needed. Large seal leaks were not confirmed to be successes and are assumed to be failures. Additional Note It is also noted that PSEG has implemented additional procedures / TSC Guidelines HC.OP-AM.TSC-0024 Rev. 5 which provides a "new" portable diesel driven pump that is proceduralized. This is estimated to provide 300 gpm by the procedure through a condensate transfer flange into RHR B. This is currently not credited in the PRA model. R.G. 1.200 from the NRC states that "If the requirement has been met for the majority of the systems or parameter estimates, and the few examples can be put down to mistakes or oversight, the requirement would be considered to be met". Therefore, the guidance given for Peer Reviews gives the Peer Review Team the discretion to consider isolated cases of omissions as deserving of a suggestion with no consequential effect on the capability category as long as it does not reflect a systematic breakdown of the PRA modeling process (See General Discussion Items). The Peer Review observation was incorporated in model update HC108B after the peer review comment. Model (HC108B) now includes the requirement for both the FPS and fire pumper truck with their associated unavailabilities and unreliabilities accounted for.
F&O SY-B14-01 Missing Common	The standard requires that failure of common piping be modeled if the failure affects more than one system. The	The treatment of the common pipe between the following could influence PRA modeling:

TABLE A-1

RESOLUTION OF PEER REVIEW F&Os

F&O	F&O DESCRIPTION	RESOLUTION
Piping Failure Modeling	common piping failure between HPCI/FW/CS and RCIC/FW have not been modeled. FINDING -The modeling provided is incomplete such that the SR is not met, and it can not be demonstrated that components/failure modes which fail multiple systems have been included.	- RCIC and FW - HPCI and FW - HPCI and CS The effects and responses can be different for each of these cases and depending on the location of the break. The three primary locations identified are the following: (1) LOCAs: Unisolable breaks inside containment - LOCAs (2) Isolable LOCAs: (a) Isolable breaks outside the first isolation valve (b) Isolable breaks outside the second isolation valve (3) Unisolable LOCAs outside containment For HPCI evaluations, because of the multiple paths into the RPV from HPCI, breaks in the FW or CS pipe do not compromise the ability for HPCI to provide adequate makeup to meet the PRA success criteria. Unisolable breaks outside containment are treated to fail all RPV injection sources in the Reactor Building. Therefore, no additional dependency treatment is needed for those cases. All common valve failures (e.g., MOVs and CVs) between HPCI/CS A and HPCI/FW A are explicitly modeled to fail the common systems. This represents a single example of possible common pipe rupture effects. It does not represent "a systematic failure to address the requirement". Therefore, because of the low safety significance and the isolated nature of this deficiency, it would appear appropriate to classify this as a Suggestion and assign Capability Category II. This model modification has been evaluated and assessed as a negligible impact on the PRA risk metrics.

TABLE A-1

RESOLUTION OF PEER REVIEW F&Os

F&O	F&O DESCRIPTION	RESOLUTION
		Nevertheless, it has been included as the highest priority model change for 2009. (See further discussion below.) No other instances of screening common components for multiple systems are identified. Therefore, the guidance given for Peer Reviews gives the Peer Review Team the discretion to consider isolated cases of omissions as deserving of a suggestion with no consequential effect on the capability category as long as it does not reflect a systematic breakdown of the PRA modeling process (See General Discussion Items).
F&O SY-A3-01 (SY-A6 is Not Met) System boundaries in system notebook	System components and boundaries are typically not defined in the system notebooks but referred to the Component Data Notebook. This is acceptable for components but the system boundaries should be defined in the system notebook. FINDING - The information provided is incomplete such that the SR is not met.	JVR to provide markups of figures to be added by BAT as a second figure giving boundary of modeled system. System boundary figures were added to Section 4 of all system notebooks as part of the 2011 PRA Update.
F&O AS-B2-01	A review of the SORV event tree indicates that with a SORV and no high pressure makeup, depressurization (ADS) is tested. Pursuing this logic on the fault tree discloses that ADS cannot fail since the probability is set to zero via an equal gate, X-IORV. This in effect removes this top event from the event tree.	This is a documentation issue only and has no impact on the ILRT extension analysis.

A.2.6 Intenal Events Gap Assessment to AMSE/ANS Combine Standard

As noted the HCGS probabilistic risk assessment (PRA) model has resolved all of the applicable findings and observations (F&Os) identified in the PRA Peer Review to meet the Capability Category II Supporting Requirements (SR) in ASME RA-Sb-2005, as amplified by RG 1.200, Revision 1.

Since the HCGS internal events PRA models were reviewed against the ASME RA-Sb2005. PRA standard, as endorsed by RG 1.200, Revision 1, a gap assessment was performed to account for the differences between those supporting requirements and the supporting requirements provided in Part 2 of the ASME/ANS PRA standard, as endorsed in RG 1.200, Revision 2. To address these differences, Section 3.3 of NEI 05-04 "Process for Performing Internal Events PRA Peer Reviews Using the ASME/ANS PRA Standard," Revision 3 was used as guidance to perform this gap assessment for the HCGS internal events PRA models. The following provides the results of this gap assessment.

1. Overview of High Level Requirement and Supporting Requirement Changes (NEI 05-04 Section 3.3)

   In general, the changes to the ASME/ANS PRA standard high level requirements (HLRs) and SRs in the transition from Addendum B (ASME RA-Sb-2005) through Revision 1, Addendum A (ASME/ANS RA-Sa-2009) were minor and include the following:

   - Incorporation into the ASME/ANS PRA standard issues that were identified by the NRC in RG 1.200, Revision 1,
   - Renumbering of the ASME/ANS PRA standard HLRs and SRs to remove deleted SRs and SRs ending with a letter (for example, SR QU-A2a); as listed in Appendix F ofNEI 05-04, Revision 3,
   - Changes in the cross-references updated to the new tables, and
   - Corrections of typographical and grammar errors, and changes in wording.

   However, there were a few examples of changes to either the ASME/ANS PRA standard or the RG 1.200, Revision 2 that would require re-evaluation of the PRA against the ASME/ANS PRA standard requirements. These are discussed in the following sections.

2. Supporting Requirements Requiring Re-evaluation (NEI 05-04 Section 3.3.1) SRs that require re-evaluation are those SRs that have changed significantly, including those with new issues identified in RG 1.200, Revision 2; these SR are provided in Table A-2.

TABLE A-2

SUPPORTING REQUIREMENTS REQUIRING GAP ASSESSMENT RE-EVALUATION

ASME/ANS RA-Sa-2009 Supporting Requirement	NEI 05-04, Revision 3, Table 3-2 Comments	RG 1.200, Revision 1 to Revision 2 Gap Assessment Re-evaluation and Capability Category (CC)
HR-06	RG 1.200, Revision, 2 provides clarification that should be evaluated.	Meets: The HCGS HRA models characterize the uncertainty in the estimates of the human error probabilities (HEPs) consistent with the quantification approach and use mean values in the quantification of the PRA results. Uncertainty cases are also provided using the 50th and 95th percentiles of the HEPs.
HR-G3	RG 1.200, Revision 2, provided clarification to items (d) and (g) of the SR. Some of the RG 1.200, Revision 1 wording remains, while some additional clarification is provided.	CC I IIIII: The HCGS HRA models use the EPRI HRA calculator, which includes a discussion of the specific scenario to evaluate; the (d) degree of clarity of the cues/indications in supporting the detection, diagnosis, and decision-making give the plantclarificationspecific and scenario-specific context of the event, and (g) complexity of detection, diagnosis and decisionmaking,and executing the required response.
New OA SR	RG 1.200, Revision 1, included a new SR - - DA-08. The recommended new SR is included in RG 1.200, Revision 2, as DA-09 (with the renumbering).	Meets: The HCGS PRA models only take credit for repairing the emergency diesel generators (EDGs) in the electric power·recovery (EPR) model. This EPR model uses a convolution methodology to calculate the probability of recovering offsite power or repairing an EDG in time to prevent core damage as a function of the accident sequence in which the sse failure appears.
QU-A2	Need to ensure QU-A2 evaluates LERF results.	Meets: The HCGS PRA models provide estimates of the individual sequences in a manner consistent with the estimation of core damage frequency (CDF) and LERF to identify significant accident sequences and confirm that the logic is appropriately reflected. These estimates are accomplished by quantifying the individual accident sequences.
QU-A3	Need to ensure QU-A3 evaluates LERF results.	CCII: The HCGS PRA models are quantified using PRAQuant. UNCERT is used to

TABLE A-2

SUPPORTING REQUIREMENTS REQUIRING GAP ASSESSMENT RE-EVALUATION

ASME/ANS RA-Sa-2009 Supporting Requirement	NEI 05-04, Revision 3, Table 3-2 Comments	RG 1.200, Revision 1 to Revision 2 Gap Assessment Re-evaluation and Capability Category (CC)
		detemine the mean CDF and LERF to be estimated by correlating event probabilities. When propagating uncertainty distributions, the CDF and LERF are estimated.
QU-B5	RG 1.200, Revision 2, provides clarification that should be evaluated. Need to verify breaking logic loops does not result in undue conservatism.	Meets: Both RG 1.200, Revision 1, Table A-1. "Staff Position on ASME RA-S-2002, ASME RA-Sa-2003, and ASME RA-Sb-2005," and RG 1.200, Revision 2, Table A-2. "Staff Position on ASME/ANS RA-Sa-2009 Part 2, Technical and Peer Review Requirements for At-Power Internal Events" have "No objection" to SR QU85.Furthermore, the HCGS PRA model logical loops are broken in a manner that still permits each dependency to be accounted for when quantified using event trees with conditional split fractions.
QU-B6	Need to ensure QU-86 evaluates LERF results.	Meets: The CAFTA event tree linking quantification process that is used by the HCGS PRA models account for system successes in addition to system failures· in the evaluation of accident sequences to the extent needed for realistic estimation of CDF and LERF. This accounting is accomplished by using numerical quantification of success probability. Since the event trees are linked, all "successes" are transferred between event trees.
QU-E3	Need to ensure QU-E3 evaluates LERF results.	CCII: The HCGS PRA models take into account the "state of knowledge" correlation between selected parameter distributions, propagate these uncertainties through a Monte Carlo quantification using UNCERT, and calculate the estimated CDF and LERF distributions.
QU-E4	Revision 1, Addendum A of the ASME/ANS Standard rewords this SR. Additionally, RG 1.200, Revision 2, provides clarification to remove Note 1.	Meets: The HCGS PRA models identify sources of model uncertainty and their related assumptions, as well as how the PRA model is affected by these.
Flooding SRs: IFPP-B1, B2, B3, IFSO-B1, B2, B3, IFSN-B1, B2, B3, IFEV-	These are new requirements for flooding that expand on the original SRs in the ASME/ANS PRA Standard.	Meets: The HCGS Internal Flooding PRA model documentation is consistent with the standard requirements. Additionally, the uncertainty is address with CDF and LERF using UNCERT.

TABLE A-2

SUPPORTING REQUIREMENTS REQUIRING GAP ASSESSMENT RE-EVALUATION

ASME/ANS RA-Sa-2009 Supporting Requirement	NEI 05-04, Revision 3, Table 3-2 Comments	RG 1.200, Revision 1 to Revision 2 Gap Assessment Re-evaluation and Capability Category (CC)
B1, B2, B3, and IFQU-B1, B2, B3.		
IFSN-A6	RG 1.200, Revision 2, provides clarification that should be evaluated.	CCIII: The HCGS Internal Flooding PRA model included investigation into component failure due to flooding induced jet impingment, humidity, condensation, temperature, etc

3. Supporting Requirements that May Require Re-evaluation (NEI 05-04 Section 3.3.2) A number of the SRs changed in the ASME/ANS PRA standard as a result of the NRC comments to remove the word "key" with respect to assumptions and sources of (modeling) uncertainty.

   The NEI guidance suggests that if the original peer review or self-assessment did evaluate the PRA against these NRC recommended wording changes, but the SR was assessed as "Not Met," then it may be useful for the gap assessment to include a re-evaluation of these 11 impacted SRs once the methods are modified per the disposition of the applicable F&O. The assessment of these affected SRs is provided in Table A-3.

TABLE A-3

SUPPORTING REQUIREMENTS AFFECTED BY "KEY" ASSUMPTIONS AND UNCERTAINTY REQUIRING GAP ASSESSMENT RE-EVALUATION

ASME/ANS RA-Sa-2009 Supporting Requirement	2009 HCGS Peer Review SR Capability Category	Associated F&O	RG 1.200, Revision 1 to Revision 2 Gap Re-Evaluation
IE-D3	Meets	None	Meets: Previously assessed as "Meets." No re-evaluation required.
AS-C3	Meets	None	Meets: Previously assessed as "Meets." No re-evaluation required.
SC-C3	Meets	None	Meets: Previously assessed as "Meets." No re-evaluation required.
SY-C3	Meets	None	Meets: Previously assessed as "Meets." No re-evaluation required.
HR-I3	Meets	None	Meets: Previously assessed as "Meets." No re-evaluation required.
DA-E3	Meets	None	Meets: Previously assessed as "Meets." No re-evaluation required.
QU-E1	Meets	None	Meets: Previously assessed as "Meets." No re-evaluation required.
QU-E2	Meets	None	Meets: Previously assessed as "Meets." No re-evaluation required.
QU-F4	Meets	None	Meets: Previously assessed as "Meets." No re-evaluation required.
LE-D6 (LE-D5 in ASME RA-Sb-2005)	N/A	None	Not applicable to BWRs
LE-G4	Meets	None	Meets: Previously assessed as "Meets." No re-evaluation required.

4. SRs Not Requiring Re-evaluation (NEI 05-04 Section 3.3.3)

   A number of the SRs changed between Addendum B (ASME RA-Sb-2005) and Revision 1, Addendum A of the ASME/ANS PRA standard (ASME/ANS RA-Sa-2009), which do not require re-evaluation during a gap assessment. These include the numbering changes to the SRs and minor editorial changes. NEI 05-04 Rev. 3, Appendix F provides a cross-reference table of the SR numbering changes.

5. Conclusions

   There were some editorial revisions and clarifications to the internal events PRA standard from the 2005 version to Part 2 111nternal Events11 of the 2009 combined standard. The NRC, in RG 1.200, Revision 2, endorsed this combined standard and did not identify any exceptions. The internal events supporting requirements are essentially the same in the

two standards since there are no substantive technical changes to the internal events PRA standard. This along with the NEI 05-04 Section 3.3 gap assessment provided above for the HCGS internal events PRA model, provides the basis that the HCGS internal events and internal flooding PRA models are also fully compliant with RG 1.200, Revision 2, Capability Category II or better. Therefore, the HCGS internal events PRAs based on RG 1.200, Revision 1, also conform to RG 1.200, Revision 2, and use of the current HCGS PRA models to perform the ILRT extension risk assessment would have no impact on this application.

A.2.6 External Events

Although EPRI report 1018243 [A.8] recommends a quantitative assessment of the contribution of external events (for example, fire and seismic) where a model of sufficient quality exists, it also recognizes that the external events assessment can be taken from existing, previously submitted and approved analyses or another alternate method of assessing an order of magnitude estimate for contribution of the external event to the impact of the changed interval. Based on this, currently available information for external events models was referenced, and a multiplier was applied to the internal events results based on the available external events information. This is further discussed in Section 5.7 of the risk assessment.

The current Fire PRA Model is considered adequate for risk insights, and other applications if limitations are understood and taken into account. The conservative nature of the Fire PRA modeling and the present status of Fire PRA development lead to these limitations (see section 5.7 for additional details). A Fire PRA peer review was performed in November, 2010 [A.9]. Table A-4 summarizes the Fire PRA Peer Review results. The peer review focused on compliance to the ASME/ANS standard [A.6]. Although not identified by the peer review team, there is believed to be conservatisms that can be addressed in future updates that will lead to an overall reduction in CDF contribution.

The Fire PRA Peer review did not identify issues that would preclude using the PRA results in performing an "order of magnitude" estimate for the ILRT risk assessment.

Therefore, the quality of the Fire PRA is sufficient to support an order of magnitude HCGS ILRT external events risk impact assessment.

TABLE A-4
RESOLUTION OF FPRA PEER REVIEW F&Os

F&O		F&O DESCRIPTION	RESOLUTION
1-1	ES-C1 ES-C2 ES-D1	Per HC-PSA-21.03, the effects of instrumentation are not evaluated (Section 3.4.5). It is assumed that instrumentation and indication are redundant and diverse and therefore none need to be credited.	In the 2014 FPRA update, detailed modeling for instruments and alarms was not able to be incorporated due to a lack of cable data for these components. Given the multiple, redundant instrumentation relied upon by the operators for observing and assessing containment leakage, it is unlikely that all instrumentation useful for this assessment would be affected by a single fire modeled in the PRA.
1-3	ES-A1 FQ-A2	HC-PSA-21.03 Section 3 All Failures are quantified utilizing the Plant Trip initiator with added equipment failure. Table 3-2 Comparing the effects of Initiating Event failures vs. Fire Initiator does not appropriately characterize the gap between Initiators with significant CCDPs such as LOOP, SACS, DCA/DCB and the Fire Initiator treatment (examples). The intent of FQ-A2 is to ensure that the selected initiating event, or events, encompasses the risk contribution from all applicable initiating events.	In the 2014 Fire PRA update, a Fire Initiating Events Decision Tree was incorporated into the fault tree model to route system failures to the appropriate accident sequence. A review of the cutsets shows that the fire initiating events are appropriately routed through the applicable sequence trees.

TABLE A-4
RESOLUTION OF FPRA PEER REVIEW F&Os

F&O		F&O DESCRIPTION	RESOLUTION
1-5	QU-E1 IGN-B5 UNC-A2	Assumptions made in the plant partitioning and ignition frequency calculation should be clearly defined in the document, with basis. Examples: Use of Zero cable loading for areas with low load (Small, Non-zero may be more appropriate) based on no data in the App R documentation of combustible loading. Some of these areas have at least some cable loading (though likely small). The use of zero frequency may be inappropriate in that no scenario is identified for later inclusion in fire scenarios. No walkdowns are provided to confirm the assumption that zero loading is appropriate. Provide a basis for this assumption of zero cable loading. Ignition sources not walked down due to inaccessibility. - There is an implied assumption that the methods used are equivalent to walkdowns. Clarification should be provided that it is assumed to be equivalent to performing walkdowns, and provide a basis for why the assumption is valid. No sources of uncertainty are documented in HC-PSA-21.02 (Partitioning and IGF). These must be identified and their effects discussed. Uncertainty and Sensitivity analysis and Appendix D contains a brief discussion of uncertainties related to source counting, and the availability of updated IGF data (EPRI). No discussion is made on the uncertainties created due to the NUREG/CR-6850 IGF parsing method, including the division of a single plant ignition frequency among all members of a bin type regardless of actual component function or run time.	Additional detail regarding zones with zero cable loading, inaccessible ignition sources, source counting, ignition frequency allocation, and relevant assumptions and uncertainties was added to the FPRA documentation in the 2014 update.
1-6	HR-E1 HR-E2 HRA-A2	The plant does not model in the FPRA the impact from operator use of the existing fire response procedures (for example, HC.OP-AR.QK-0002(F) - Rev. 18).The model provided for review did not include the existing or future procedures, therefore there was nothing to review.	During the 2014 FPRA update, cutset reviews with plant operators included discussions of fire response procedures and risk significant scenarios where fire response procedures were applied. These were applied to the affected scenarios.
1-9	ES-A1 ES-D1	The SSA analysis requires HVAC in many areas. Most HVAC is screened in Appendix B based on not being in the Internal Events Models. Calculations were provided that support IE assumptions, however no evidence was provided that the SSA was reviewed as applicable to the Fire PRA.	During the 2014 FPRA update, a review of HVAC dependencies was performed. Additional discussion regarding the treatment of HVAC components was added to the documentation.

TABLE A-4
RESOLUTION OF FPRA PEER REVIEW F&Os

F&O		F&O DESCRIPTION	RESOLUTION
1-11	UNC-A2	IGN-A10 - Statistical uncertainties related to ignition frequencies are calculated as described in IGNA10, however, these are not propagated through individual scenarios or into an uncertainty that is applied to the final CDF at the Scenario or Plant level.	During the 2014 FPRA update, the treatment of ignition frequency uncertainty was re-evaluated. Additional discussion of ignition frequency uncertainty was added to the documentation.
1-17	FSS-A1 FSS-A4 FSS-A5 FSS-D10	Walkdown results - The plant walkdowns in RB2 Room 4303 indicate that 5 scenarios which should have been evaluated as transients. Only two were found in the documentation (scenarios D15 and D16). Missing scenarios (all transient fires) include: Scenario 1: 10' x 4' area, hits trays (Vertical) 12NTLO90 12NTLP90 scenario 2: 12' x 4' area hits trays (vertical) 12NTMQ91 12NTFQ91 Scenario 3: 20' x 4' on inside (curved) wall hits conduit (horizontal about 4' above floor) 12NRLP30 AB3 Room 3442: walkdowns identified 2 areas where transients should be considered, none were found in the documentation. Scenario 1: At the far end of the room (from the entrance) directly underneath the cables at the wall (including wall effects). Scenario 2: On the platform area across from the entrance doorway, conduits and black cables protruding from the floor and along wall (appear to be possible fiber optics). This appears that the actual practice of placing transients may not have included all places where vertical risers would have been affected, or where low horizontal conduits should have been targeted.	During the 2014 FPRA update, new plant walkdowns were performed to identify new fire scenarios and sources, including verifying existing transient fires and evaluating any new transient fire locations. These walkdowns were documented.

TABLE A-4
RESOLUTION OF FPRA PEER REVIEW F&Os

F&O		F&O DESCRIPTION	RESOLUTION
1-18	FSS-A1	Lighting and Distribution panels were not counted (as a whole). 2' x 3' - 3' x 5' panels were observed in the plant during Peer review walkdowns. NUREG/CR 6850 counting criteria would not exclude these panels, nor would they be excluded per FAQ-16. These should have been selected and counted as ignition sources. 2' x 3' - 3' x 5' boxes were observed in the plant. Suggest review of criteria in FAQ 16 and document a disposition of large boxes with no instrumentation. If necessary interviews with electrical personnel, drawing reviews, and or opening of boxes should be used to appropriately disposition whether these should be not binned, or binned as junction box, pull box, or electrical cabinet.	During the 2014 FPRA update, new plant walkdowns were performed to identify new fire scenarios and sources, including verifying existing transient fires and evaluating any new transient fire locations. These walkdowns were documented. Lighting panels of this type were not included in as sources. These panels count as less than 1 EEU (i.e., very small source) and inclusion would dilute the bin frequency and reduce the importance of other risk significant sources.
1-20	QU-B1 QU-F5 FQ-B1	Software utilized in quantification of the Fire PRA is FRANC, XINIT, and CAFTA (as part of the R&R Software suite). An overview of the use of these codes is provided in HC-PSA-21.06 Section 3.14. These codes are accepted as PRA industry standard codes for quantification of Fire PRA. However, no discussion is provided as to the limitations or features of the codes that could impact results. In fact, Appendix E shows that there are differences in the use of FRANC vs. XINIT for quantification, but no discussion is provided as to the reason for the quantification difference. Some differences are attributed to Min-Cut Upper bound approximation. Examples of impacts due to the codes chosen include: Impacts of the Min-Cut-Upper bound quantification method and Rare Event Approximation when used in quantifying high probability failures.	In the 2014 FPRA update, a discussion regarding FRANX and its limitations and use was added to the documentation.
1-21	QU-F2 QU-B3 FQ-B1	HC-PSA-21.06 Section 5.3 A truncation sensitivity is performed to validate the reasonableness of the chosen truncation limit. The change in CDF from the chosen truncation level to the next higher truncation level is less than 5%. For LERF this is less than 1% change. However, only two points are quantified which only provide one data point for the change in CDF (LERF). No convergence of results is demonstrated, which would require quantification of at least three successive truncations to provide more than one delta CDF (LERF) and thus demonstrate a trend in decreasing change in CDF (LERF).	In the 2014 FPRA update, CDF and LERF were requantified with a new truncation study to demonstrate convergence. This was documented.

TABLE A-4
RESOLUTION OF FPRA PEER REVIEW F&Os

F&O		F&O DESCRIPTION	RESOLUTION
2-5	HRA-A3	The impact of instrument failures and maloperation on operator response actions was not considered in the HC Fire PRA.	See response to F&O 1-1.
3-2	IGN-A1	Section 3.0 of the Hope Creek Plant Partitioning and Fire Ignition Frequency Development (Report HCPSA-21.02) states that the generic fire ignition frequencies from NUREG/CR-6850 (task 6) were used as the base values for allocation of fire frequencies to fire initiators. Use of this data does not take into account the revised and more current fire frequencies provided in FAQ 08-0048/EPRI 1016735. Most of the fire ignition frequencies provided in NUREG/CR-6850 remain unchanged by FAQ 08-0048/EPRI 1016735 because this document contains the most current information, the updated values should be used to establish initiator fire frequencies. With this one exception the method used to assign fire frequencies satisfies the SR therefore this SR is met with one finding.	During the 2014 FPRA update, the Bayesian FIF updating was re-performed using both the old NUREG/CR-6850 priors (for historical purposes), the new NUREG/CR-2169 priors, and posteriors for both. Both methods were included in the documentation. The new NUREG/CR-2169 FIF results were used in the 2014 FPRA.
3-5	IGN-A4	Based on the review performed, no potentially challenging fires were identified although two fires could have been considered indeterminate and one potentially challenging. The fires identified as indeterminate were cases 8 and 9 in the Hope Creek - Recent Fire Incident Review For Potentially Challenging Events. Each of these involved dry cask building light fixtures one of which was responded to by the onsite fire department. Details of the fire intensity and required extinguishment is not specifically given and the fire report does not indicate that the fire was significant. However since these fires were reviewed using the NUREG/CR-6850 criteria, a subjective evaluation of these fires should be included (Ref. C.3.3.2). Fire number 5 identifies an incident where a fire developed on the outlet hose of a DOP aerosol generator. The fire was spreading along the outlet hose until extinguishment by isolation of the power source by the equipment operator. Because this event required active intervention to extinguish the fire and prevent its continued spread this event should be considered potentially challenging according to the subjective criteria listed in NUREG/CR-6850 Section C.3.3.2. This SR is considered met with an F&O identified for the potentially challenging fire that was not identified.	For the 2014 FPRA update, plant records regarding recent fires were reviewed for incorporation into the Bayesian FIF updating. These were documented and incorporated in the FIF calculations as appropriate.

TABLE A-4
RESOLUTION OF FPRA PEER REVIEW F&Os

F&O		F&O DESCRIPTION	RESOLUTION
3-7	SF-A2	According to Section 4.8.1.2 of the IPEEE an evaluation was performed to identify suppression and detection systems that could be inadvertently actuated by a seismic event. However this evaluation was limited to the robustness of electrical relays in in detection systems and robustness of suppression system piping in suppression systems located in safety related areas. The assessment required by this element is intended to identify the effects of inadvertent operation of these type systems anywhere in the plant including actuation of a system in a non-safety area. The evaluation performed by the IPEEE falls short of the current requirement therefore this SR is considered not met.	In the 2014 FPRA update, a discussion of inadvertent fire suppression system actuation was added to the documentation. It was determined that spurious actuation of fire suppression systems does not represent a risk to post-earthquake response actions.
3-8	SF-B1	Section 1.2.4 of the Hope Creek Fire Probabilistic Risk Assessment Summary and Quantification Notebook (HC-PSA-21.06) documents the results of the seismic fire interaction analysis included in the 1997 IPEEE. This discussion addresses the results and insights gained from the IPEEE evaluation. However it is not considered sufficient to facilitate Fire PRA applications, upgrades, and peer review since the IPEEE does not document all of the required Seismic/Fire Interactions required by the SF requirements. Accordingly this SR is considered not met and an F&O has been prepared.	In the 2014 FPRA update, a discussion of seismic-fire interactions considering all available guidance was added to the documentation to meet the SR requirements. This does not affect quantification or risk insight conclusions.
3-9	SF-A3	Section 4.8.1.3 of the IPEEE documents an evaluation of the seismic degradation of fire suppression systems. The evaluation performed was limited to fire suppression systems located in safety related areas, the fire water pumphouse, and water storage tanks. This analysis acknowledges that the primary concern is failure of the non-seismic fire water pumphouse and water storage tanks however the assessment does not extend beyond development of this one common-cause failure. Due to the limited nature of this assessment this SR is considered not met and a finding is generated to expand the evaluation performed.	In the 2014 FPRA update, a discussion of seismic-fire interactions considering all available guidance was added to the documentation to meet the SR requirements. This does not affect quantification or risk insight conclusions.
3-10	FSS-C1	According to the Fire Scenario Report (HC-PSA-21.05) and the Hughes Generic Fire Modeling Treatment the ZOI for fire initiators is based on bounding calculations developed in the Generic Fire Modeling Treatment. These generic ZOIs are then applied in the plant to identify targets within predetermined ZOIs.	In the 2014 FPRA update, fixed source and transient fire sources were re-evaluated using more refined fire modeling treatments. The non-suppression probabilities were also re-evaluated to include time-dependent heat release rates. This was also documented.

TABLE A-4
RESOLUTION OF FPRA PEER REVIEW F&Os

F&O		F&O DESCRIPTION	RESOLUTION
3-11	FSS-C2 FSS-C3 FSS-D3	The ZOIs applied in the field to identify targets are based on fire modeling that assumes a peak full intensity HRR as discussed in Appendix B of the Hope Creek Fire Probabilistic Risk Assessment Fire Scenario Notebook. Additionally, the development and use of these ignition source intensities does not incorporate time dependent HRRs.	See response to F&O 3-10.
3-12	FSS-D5	The fire modeling tools and results derived from the Hughes Generic Fire Modeling Treatments Report have a sound technical basis. Per the discussions in this document, the empirical relationships employed provide reasonable results that are not considered overly conservative. A nonconservative empirical model is used to describe the HRR for transient fires at Hope Creek. This model is discussed in detail in Section 8.0 of the Hope Creek Fire Probabilistic Risk Assessment Fire Scenario Notebook. According to this model a transient fire has a HRR of 69 kW which is equivalent to a 98% electric motor fire as defined in NUREG/CR-6850. This empirical model is based on an assertion that industry experience does not support using a transient HRR approaching that proposed in NUREG/CR-6850 and that the transients upon which these fire are based are not representative of the nuclear industry. Also because an initiator is needed to ignite a transient these fires are assumed to be akin to a temporary cable installation and accompanying combustible loading which is equated to the HRR provided by an electric motor. This treatment is considered potentially nonconservative because it assumes that generally accepted transient HRRs are overly conservative without benefit of a statistical analysis that supports this conclusion.	In the 2014 FPRA update, transient fires were re-evaluated using the appropriate HRR distributions in NUREG/CR-6850. See also the response to F&O 3-10.

TABLE A-4
RESOLUTION OF FPRA PEER REVIEW F&Os

F&O		F&O DESCRIPTION	RESOLUTION
3-14	FSS-C6 FSS-D3	The generic use of fire modeling resulted in Fire Scenario AB3/BG being one of the top risk contributors in the Fire PRA. According to the Quantification notebook this scenario contributes approximately 6% of the total CDF. This scenario postulates a whole room fire for Room 3442. Due to the significance of this scenario this room was walked down. The walkdown indicated that most of this room is a contaminated space with limited access, however because the room is essentially devoid of equipment the entire area was observable from a platform located at its north end. The room is long and narrow but results in a relatively large volume. This area contains a single hoist mounted on a crane rail the runs the length of the room at the ceiling elevation. Most of the raceways (conduits) in this room are located in the contaminated space at the south end of the room on the west wall (floor to ceiling locations). At its closest approach the hoist motor would be located approximately 3 to 4 feet from the wall mounted conduits. Based on the walkdown it appears that a fire in the hoist motor would not likely damage the wall mounted conduits very quickly if at all. Additionally it's unlikely that this fire or a transient fire in this room would be capable of generating an HGL due to the lack of secondary combustibles. It appears from the walkdown that the risk evaluation for this room contains a significant amount of conservatism that should be addressed through the application of detailed fire modeling.	In the 2014 FPRA update, MCA scenarios for this area (AB3) were refined to only impact equipment at or above the ignition elevation.
3-16	FSS-G4	As discussed in the process flowchart contained in the Multi-Compartment Analysis Report (HC-PSA-21.07) fire barrier failure probability is based on the failure of a single Type 1 (fire, security, and water tight doors) barrier component. However barrier failure should account for the potential failure of any number of barrier components in a wall. The probabilities of the various barrier components contained in a barrier segment should be ORed together to account for the cumulative failure probability of the openings. The current approach may underestimate the cumulative barrier failure probability.	In the 2014 FPRA update, MCA scenario severity factors were recalculated for all MCA scenarios to account for all possible barrier failure combinations.

TABLE A-4
RESOLUTION OF FPRA PEER REVIEW F&Os

F&O		F&O DESCRIPTION	RESOLUTION
4-1	HR-G3 ES-A5 HRA-A3 HRA-C1	The documentation indicates that instruments being relied upon by operators for adequately performing the operator actions were specifically not part of the equipment selection process. This can significantly affect the assessment of plant mitigation capability. In addition no documentation was available to indicate the evaluation of spurious alarms resulting in undesired actions.	See response to F&O 1-1.
4-2	ES-B1 ES-D1	Most of the instrumentation in the SSEL, i.e. reactor level, reactor pressure, RCIC indications, etc. were not selected. The disposition was typically based on redundant equipment availability. This however, does not explain the possibility of fire damage to redundant equipment. Suppression pool level indication not included. Min flow bypass considered adequate without sufficient justification. HVAC is not considered however, several HVAC actions (swgr. room cooling; initiate HVAC, etc.) have been considered in Table L-1.	In the 2014 FPRA update, each component on the SSEL was individually dispositioned for inclusion in the FPRA based on its success criteria. Indicators that were not associated with any credited operator action and unlikely to cause unwanted actions were not included. This was confirmed during cutset reviews (which included plant operators) for risk significant scenarios.
4-3	ES-D1	There is a significant weaknesses in the equipment selection documentation, including a lack of analysis or documentation in the areas of a) Operator manual actions (OMA) support instrumentation b) Alarm response review for un-desired actions c) Dependent/interlocked components d) HVAC equipment disposition e) FPIE initiating events review f) FPIE systems review g) Lacking MSO review of current BWROG list.	The 2014 FPRA Update incorporated a more detailed HRA treatment, breaker coordination review, disposition of HVAC equipment, Fire Initiating Events Decision Tree, and updates to address Multiple Spurious Operations review from the current BWROG list. This F&O is a summary F&O of other F&Os.
4-7	HR-G3 PRM-B5 HRA-C1 HRA-D1	The plant does not model in the FPRA the existing fire response procedures. Additionally, the fire response procedures include a number of recovery actions that will likely impact the FPRA. For example, on a fire in one of the HVAC areas, operators are directed to start the opposite train of HVAC. These actions are not modeled in the FPRA.	See response to F&O 1-6.

TABLE A-4
RESOLUTION OF FPRA PEER REVIEW F&Os

F&O		F&O DESCRIPTION	RESOLUTION
4-8	FSS-A6 FSS-B1	MCR abandonment calculations primarily assumed that HVAC was available in the normal mode. It should be verified that the postulated fire is not capable of disabling one or more components of the mechanical ventilation system. The CDF could increase significantly if ventilation is assumed to be lost. Noted that transient scenarios (D) were not considered in the MCR. It should be verified that the postulated fire is not capable of disabling one or more components of the mechanical ventilation system.	In the 2014 FPRA update, a re-analysis of MCRAB failure modes and logic, including explicit treatment of the Remote Shutdown Panel functions, was incorporated and documented. The treatment was confirmed during cutset reviews with plant operations. Procedure review and discussion with operations confirmed that plant personnel will abandon the MCR upon detecting smoke, as directed by plant procedures. HVAC is not assumed to be available or necessary for this analysis.
4-9	FSS-A6	Detailed calculations were not performed for failure of alternate shutdown capability for the scenarios resulting in MCR abandonment. A conservative value of 0.1 was used. However, if the scenario results in an MSO that fails the ASP, then the 0.1 value could potentially be non-conservative.	In the 2014 FPRA update, a re-analysis of MCRAB failure modes and logic, including explicit treatment of the Remote Shutdown Panel functions, was incorporated and documented. The treatment was confirmed during cutset reviews with plant operations.
4-11	FSS-D7	In the fire scenario development, no credit was taken for suppression and detection. The analysis does not exercise all the fire modeling tools available such as credit for suppression and detection and calculation of non-suppression probability.	In the 2014 FPRA update, non-suppression probabilities were re-calculated with credit for suppression and detection capabilities available for each scenario.
4-12	FSS-D3	Statistical models were not used for suppression, detection and severity factor calculations. MCB HRRs were based on conservative statistical models. The SFs shown in Table 9-1 of the fire scenario notebook are based on review of fire events and not on statistical models.	In the 2014 FPRA update, non-suppression probabilities were re-calculated with credit for suppression and detection capabilities available for each scenario. Operating experience was also reviewed for fire events.
4-14	FSS-D8 FSS-H7	Other than for Multi-compartment analysis, fire detection and suppression systems are not credited for the analyzed fire scenarios. For the MCA Suppression credit, these systems were not 'walked down' to assess the effectiveness in controlling the postulated fires.	In the 2014 FPRA update, non-suppression probabilities for MCAs were re-calculated with credit for suppression and detection capabilities available for each scenario. Each scenario has a 5-min non-detection probability applied. The related calculation assumes a 15-min delay before manual suppression is initiated. Based on NUREG/CR-6850, this is a conservative treatment.
4-16	FSS-F1 FSS-F2 FSS-F3	Structural steel analysis/fireproofing and potential for structural steel collapse has not been performed. See Section 10.3 of the fire scenario notebook which describes this as an open item.	In the 2014 FPRA update, an analysis of the potential for structural steel collapse was performed and documented.

TABLE A-4
RESOLUTION OF FPRA PEER REVIEW F&Os

F&O		F&O DESCRIPTION	RESOLUTION
4-21	FSS-H7	No credit has been taken for firefighting activities including fire detection, fire suppression systems, and manual suppression in the fire scenario development process. The MCR fire scenarios indirectly consider manual suppression credit in main control room abandonment calculations.	In the 2014 FPRA update, non-suppression probabilities were re-calculated with credit for suppression and detection capabilities available for each scenario.
4-22	FSS-H8	Multicompartment screening analysis is described in the HGL and Multi-compartment Analysis notebook. A conservative approach based on assumed HRRs, compartment geometry, and probability of non-suppression was used. The screening analysis provided is not based on NUREG/CR-6850. The un-screened compartments have been included in the open item list for further evaluation. The task is incomplete since the unscreened compartments have not been further evaluated. The CDF quantifications do not account for multicompartment scenarios.	In the 2014 FPRA update, MCA scenarios were re-assessed to account for all possible connections. Additionally, fire modeling was updated to use NUREG/CR-6850 data and updated HRRs. The documentation describing the screening approach was revised.
4-23	FSS-H10	The FSS walkdown process has not been documented, i.e. formal walkdown procedure has not been used which describes the purpose of each walkdown conducted, dates, participants and results. Per the SR note: Typical walkdown results may include the purpose of each walkdown conducted, dates and participants, supporting calculations (if any), and information gained. This was not documented as a part of the FPRA.	In the 2014 FPRA update, a description of walkdown methodology was added to the documentation.
4-24	FSS-C6	The modified damage criteria based on presence of HGL or elevated temperatures in the area have not been used, since the HGL contribution is not factored in the calculations.	In the 2014 FPRA update, treatment of HGL fires was updated to account for appropriate HRRs and all appropriate HGL scenarios.

TABLE A-4
RESOLUTION OF FPRA PEER REVIEW F&Os

F&O		F&O DESCRIPTION	RESOLUTION
4-26	FSS-G1 FSS-G3	Multicompartment analysis uses a screening method as described in the HGL and Multi-compartment Analysis notebook. The methodology did not apply the SRs FSS-C1 through FSS-C8. A conservative approach based on assumed HRRs, compartment geometry, and probability of non-suppression was used. The screening analysis provided is not based on NUREG/CR-6850. The un-screened compartments have been included in the open item list for further evaluation. The task is incomplete since the unscreened compartments have not been further evaluated. The CDF quantifications do not account for multicompartment scenarios. The screening criteria as defined in SR FSS-G2 has been applied to all fire zone scenarios. However, the unscreened compartments have not been evaluated further for potential damage to multicompartments.	In the 2014 FPRA update, MCA scenarios were re-assessed to account for all possible connections. Additionally, fire modeling was updated to use NUREG/CR-6850 data and updated HRRs. The documentation describing the screening approach was revised. No screening of MCAs was used.
4-28	FSS-G4	Passive fire barrier systems have been credited on a screening basis. Specific review of passive barriers, their rating consistent with applicable test standards, effectiveness and reliability and random failure has not been performed (failure probability was applied for only one scenario only).	In the 2014 FPRA update, MCA scenario severity factors were recalculated to account for all possible barrier failures.
4-29	FSS-G5	The effectiveness, reliability, and availability of the active fire barrier element has not been performed.	In the 2014 FPRA update, non-suppression probabilities were re-calculated with credit for suppression and detection capabilities available for each scenario. The reliability of all barrier types was incorporated as the barrier failure probability.
4-31	FSS-G2	The screening criteria described in HGL and Multi-compartment Analysis notebook did not consider the impacts of secondary or intervening combustibles and tray to tray fire propagation in calculation of HGL. Other assumptions considered such as cabinet height, ceiling height, and ignition source HRR interjects uncertainty into this analysis. The values used should be reflective of actual plant conditions.	In the 2014 FPRA update, MCA scenarios were re-assessed to account for all possible flowpaths. The HRRs were also re-assessed to account for actual plant conditions.

TABLE A-4
RESOLUTION OF FPRA PEER REVIEW F&Os

F&O		F&O DESCRIPTION	RESOLUTION
4-32	FSS-A5 FSS-C1 FSS-C2 FSS-D3	Fire scenario notebook, section 10.4 discusses the use of "Location Factors" related to both fixed and transient ignition sources. Appendix B of the report provides a summary of the scoping fire modeling zone of influences (ZOI), i.e. vertical and horizontal damage distance from the ignition source. These distances are based on pre-defined HRRs for various fuel packages. These HRRs and corresponding horizontal and vertical distances have not been adjusted to account for location factors.	In the 2014 FPRA update, confirmatory walkdowns were performed to refine fire scenario modeling, including consideration of target distances for fixed and transient sources.
4-33	CF-A1	Circuit failure probabilities were based on industry wide generic failure probabilities, based on Table 5-1 of the Scenario Notebook. However, component and cable specific analysis of circuit failure probabilities for significant contributors has not been performed.	In the 2014 FPRA update, detailed circuit failure analysis (e.g., for spurious operations) was applied as required to relevant components. NUREG-7150 was also applied.
4-34	UNC-A2 CF-A2	No uncertainty discussion was provided for the assigned circuit failure probability calculations.	In the 2014 FPRA update, a discussion of uncertainty in the assigned circuit failure probabilities was included. The circuit failure mode likelihood analysis used the probability estimates prescribed in NUREG/CR-7150.
5-1	CS-A6 CS-B1 CS-C4	The Model Development Notebook page 1-4 states the following: 'Breaker coordination evaluations were not performed as part of this update. It was assumed that coordination exists as demonstrated by the current plant configuration.' Table 3-1 of the Fire PRA model Development identifies a number of new MCCs and other power supplies added due to the PRA. However, the Fire SSA coordination analysis includes both SSA and non-SSA components. A spot check of added PRA components was performed, and these PRA components were found to be coordinated. However, a review of the FPRA components was not performed as a part of the FPRA documentation. As a result, SR CS-B1 is considered not met for CC II (Met CC I) since the review of additional circuits and cables that could challenge power supply availability was not performed against the existing SSA circuit evaluation.	In the 2014 FPRA update, a breaker coordination analysis was performed and incorporated into the FPRA.

TABLE A-4
RESOLUTION OF FPRA PEER REVIEW F&Os

F&O		F&O DESCRIPTION	RESOLUTION
5-3	CS-A2	Circuit Failure Probabilities in Table 5-1 of the Scenario Notebook include conditional circuit failure probabilities based on NUREG/CR-6850 recommended values. However, in multiple cases, the assigned CF probability is applied for any cable for any of the components modeled. This results in over conservatism in the results. For example, for HPCI and RCIC, the spurious Pump start is modeled, but the valve spurious operations are set to 0.99. As a result, any modeled pump start will result in overfeed. The model should likely include only the common control cables that affect all three components as causing an overfeed. Additionally, the independent spurious operation of the three components is not modeled as a result. Spurious SRV opening is also assumed to be a 0.6 probability, and assigned in any area where any SRV cable travels. This simplification appears to result in failure to identify cables where multiple SRVs may open, or the modeling of opening of individual SRVs due to damage of multiple cables (1 for each SRV, for example).	In the 2014 FPRA update, a Fire Initiating Events Decision Tree was incorporated into the event trees. This allows events such as HPCI overfeed to be treated appropriately. Also, the spurious operation of key system components and SRVs was revised. Locations of single and multiple SRV cables were also identified and incorporated into appropriate scenarios.
5-4	CS-A1 CS-C1 CS-C2	The Cable identification and analysis for PRA components is performed in a similar manner to the SSA components. However, there is no documentation of the analysis in either the AREVA support calculation or in the Fire PRA	In the 2014 FPRA update, a discussion of cable selection methodology was added to the documentation.
5-6	PP-B7	No walkdowns appear to have been performed for this specific purpose - to confirm conditions and characteristics of credited partitioning elements. However walkdowns were performed to assess ignition sources. The self-assessment refers to the FHA however additional walkdowns should have been performed.	In the 2014 FPRA update, additional walkdowns were performed to confirm partitions and ignition sources.
5-9	ES-A1	No comprehensive review was performed to determine equipment capable of or requiring a trip of the plant. By assuming a TT for most accident sequences, a review of equipment that can cause other initiating events such as a Feedwater Overfeed, MSIV closure, Spurious ADS, and others may not be performed (examples only). Some of these initiating events are covered under the MSO review, but not all.	During the 2014 FPRA update, a Fire Initiating Events Decision Tree was incorporated into the event trees. This allows for appropriate sequence treatment for fire scenarios based on damaged equipment impact on the plant response. This was confirmed for risk significant scenarios during cutset reviews with plant operations.

TABLE A-4
RESOLUTION OF FPRA PEER REVIEW F&Os

F&O		F&O DESCRIPTION	RESOLUTION
5-12	SF-A4 SF-A5	The Seismic Fire Interactions study performed for the IPEEE did not look at the following: 1) REVIEW of the plant seismic response procedures and Qualitatively ASSESS the potential that a seismically induced fire, or the spurious operation of fire suppression systems, might compromise post earthquake plant response. 2) REVIEW of a) plant fire brigade training procedures and ASSESS the extent to which training has prepared firefighting personnel to respond to potential fire alarms and fires in the wake of an earthquake and b) the storage and placement of firefighting support equipment and fire brigade access routes, and c) ASSESS the potential that an earthquake might compromise one or more of these features.	In the 2014 FPRA update, a discussion of seismic-fire interactions considering all available guidance was added to the documentation which addressed the two specified items.
5-16	IGN-A7	The Maintenance Occupancy and Storage Weighting Factors used for the Transient, Welding and Cutting ignition Frequencies appear to be inconsistent with NUREG/CR-6850 method. Specifically, Page 6-23 of 6850 mentions that a "low" ranking for maintenance should only be used for areas where administrative procedures prevent welding and cutting during power operation. However, Most compartments are ranked as 1 (low) on the Table 3-13 rankings. Additional guidance provided in Table 6-3 of 6850 is not consistent with the HC Fire PRA table 3-12 FP1 area is shown as a 10 for hot work, although the area only includes 6 pumps. It appears this and others are ranked this way based on the hot work allowed, versus the likely hot work that would be performed.	In the 2014 FPRA update, transient weighting factors were assigned according to an Interview Panel with detailed knowledge of plant activity as practiced, not just the administrative controls placed on each compartment. FAQ 12-0064 was incorporated which re-emphasizes that Medium / 3 should be the average value assigned.

TABLE A-4
RESOLUTION OF FPRA PEER REVIEW F&Os

F&O		F&O DESCRIPTION	RESOLUTION
5-17	DA-A4 PRM-B13 PRM-C1	Events added to the Fire PRA are included in Table I-1 of the model development calculation. However, the basis for the exposure time or other parameters are not provided. For example, most of the events are MOV Fail to Remain Open/Closed. These events use the generic failure rate and a 24 hour mission time. This mission time is typically applied to a component that is verified available or alarmed prior to the event occurring. However, there is no documentation of the verification of the MOV position or alarm. It may in fact be that the non-alarmed MOVs may have spuriously operated since the last test, or since the last time the operator verified the position. Additionally, event HPI-TDP-SS is set to 1E-05, without reference or basis provided.	In the 2014 FPRA update, a discussion of basic event probabilities and failure rates has been added to the documentation including justification for failure rates of new basic events. Also the treatment of spurious operation was updated to the NUREG-7150 current data.
5-22	SY-A24 PRM-B9	Two hardware repair events were carried over from the internal events PRA model: RHS-REPAIR-L and RHS-REPAIR-TR. These events have probabilities based upon mean times to repair for normal random failures (for suppression pool cooling) and do not account for the potentially damaging effects of fire events. These recovery events appear in 8 of the top 10 fire CDF cutsets and are among the most risk significant basic events in the fire PRA results. Including these events and the associated probabilities from the internal events model was not justified.	In the 2014 FPRA update, a more detailed discussion of these repair events and their probability calculations were added to the documentation. This was reviewed also during the cutset reviews with plant operations.
5-24	SY-B7 PRM-B9	MSOs were included in the FPRA model without consideration for actual flow rates or timing affecting CDF or core uncovery. For example, MSO of the head vents was conservatively modeled, and may not lead to a core damage event in 24 hours. Multiple SRV openings was conservatively modeled (e.g., for 2 SRVs) as a Large LOCA, without discussion on the expected flow rates.	For the 2014 FPRA update, thermal hydraulic calculations using MAAP were performed to confirm spurious operation plant response, such as spurious MSIV opening, and spurious single or multiple SRV openings. The results were incorporated into the FPRA.
5-25	IGN-B3 PRM-C1	The plant response model using FRANC includes the use of several databases, including the Scenario DB, Ignition Frequency DB, and the BEMAP DB. However, these DBs are not described in the documentation or included in a reviewed analysis file.	In the 2014 FPRA update, a description of the different databases used to manage the plant data was added to the documentation.
5-26	IGN-A5	The Fire Frequencies do not appear to be calculated on a per-reactor year basis. NUREG/CR-6850 values should be multiplied by plant availability to determine reactor year frequencies.	In the 2014 FPRA update, the fire ignition frequencies were re-calculated on a per-reactor-year basis.

TABLE A-4
RESOLUTION OF FPRA PEER REVIEW F&Os

F&O		F&O DESCRIPTION	RESOLUTION
5-27	IGN-A10	HC-PSA-21.02 Table 3-2 Provides the mean values and error factors based on the Bayesian updated ignition frequencies for all fire Ignition source bins. Frequencies calculated on a Fire Area Basis were estimated with a single EF = 3. No evidence is available that these factors are propagated through the analysis further (e.g., to individual scenarios) As a result, the Fire Frequencies in the combined cutsets were included in the results with a mean value, but no uncertainty intervals.	In the 2014 FPRA update, a more detailed discussion of fire ignition frequency uncertainty was added.
5-28	CS-A11 CS-C3	Assumed cable routing was used. HC-PSA-21.05 Rev. 1 appendix A provides the tables for documenting the basis for manual inclusion and manual exclusion of the BEs associated with these assumed cable routings for a specific compartment/scenario. However many of these bases are blank. 46 of the 49 scenarios that have excluded BEs do not have notes providing a basis for excluding the referenced BEs based on the assumed cable routing.	In the 2014 FPRA update, a more detailed bases of manual inclusion and exclusion of BEs was added to the documentation.
5-30	HR-E3 HR-E4 HR-G5 HRA-A2 HRA-A4 HRA-C1	No operator Interviews or talk throughs were performed for the HEPs identified as applicable to the Fire PRA. No operator Interviews or talk throughs were performed for interpretation of the procedures with plant operations or training personnel to confirm that interpretation is consistent with plant operational and training practices. No simulator observations or talk-throughs with operators were performed to confirm the response models for scenarios modeled	In the 2014 FPRA update, operator interviews were performed and added to the documentation. Plant operators were also involved with cutset reviews.
5-32	HR-I3 HRA-E1	Sources of uncertainty are documented in the FPRA quantification analysis, section 3.18. This includes a discussion on the assumption that instruments are available and failure to interview operators for the HEPs credited. However, no discussion of the factors affecting the important HEPs was discussed. For example, the top HEP (0.1 assumed control room abandonment) was not discussed as to its uncertainty and impact on the results. Other factors affecting individual HEPs was not discussed.	In the 2014 FPRA update, detailed documentation of the development of each HEP modeled was included in the documentation.

TABLE A-4
RESOLUTION OF FPRA PEER REVIEW F&Os

F&O		F&O DESCRIPTION	RESOLUTION
5-33	FSS-C4	The severity factors used for transient fires (.01 and 0.08) were reviewed and did not appear to be well supported. The 0.08 value is based on a review of 6 fire events, determined not to be an aggressive fire. However, event 56 (unknown challenging) was a "large wooden rack of blueprints" and was considered not "aggressive" due to location. Event 450 was "Heater element failure (ground fault) cause smoke which actuated deluge system. Heater extinguished when breaker tripped." This event, considered challenging, actuated a deluge system. Review of other events indicates that many of these fires may impact SSD components, depending on severity, location and non-suppression. The 0.01 factor is added to "reflect the conditional probability that a potentially critical target may be exposed or otherwise affected by a hot work related fire." Review of the data and the supporting analysis does not appear to support this 0.01 (insufficient data, and numerous data where the damage area is unclear). This severity factor also double counts the "area factor" used to reduce the ISDS Fire Area ignition frequency to a scenario specific ignition frequency. For example, Scenario CD10, D12 reduces the ISDS Bin 5 number from 3.88E-6 to 3.68E-09 through the 0.01 and a 0.1 area reduction factor (100 feet/1000 feet assumed).	In the 2014 FPRA update, transient ignition frequencies were re-calculated to reflect a ZOI of 100 sq. ft., or 10% of the PAU floor area for cable tray fires. A detailed breakdown of the calculation and related factors was added to the documentation.
5-34	FSS-C4	The Severity factors for Electrical Cabinets used in the Fire PRA do not appear to be supported, and appear to be non-conservative. The 0.05 severity factor for switchgear fires appears to have a math error (in the denominator), and has been revised in the draft ERIN report to 0.13. Similarly, the MCC severity factor has been revised from 0.05 to 0.12. Finally, low voltage panels have been revised from 0.005 to 0.02. Overall, the use of the EPRI Data in developing fires is difficult. First, the description of the events is often times unclear as to whether the severity factor can be calculated. In this case, the events do not always specify if flames do in fact come out of the cabinet of interest. Second, the application of the severity factor means the analyst can not later apply HRR severity factors (and the associated timing) or suppression, since the severity factor results are not independent of HRR and suppression.	In the 2014 FPRA update, the electrical cabinet severity factors were revised to account for time-adjusted fire growth HRRs, potential for suppression, and growth to HGL or MCA. It also uses the latest industry data.

TABLE A-4
RESOLUTION OF FPRA PEER REVIEW F&Os

F&O		F&O DESCRIPTION	RESOLUTION
5-35	FSS-C4	The "Area factors" applied to the transient fires does not appear to take into account the possible length of a cable tray or trays overhead. For example, a cable tray could wind around a room, to where a transient fire in the majority. In most cases, the scenario involved a number of cable trays, where it is not clear if the damage to a single tray is the main issue or if the damage to any of the trays can cause the event of concern. Note that the application of this severity factor plus the 0.01/0.08 transient factors in F&O 5-33 basically make all transient fires insignificant.	In the 2014 FPRA update, transient ignition weighting factors were re-calculated to reflect a ZOI of 100 sq. ft. A factor of 0.1 was used for cable tray fires, representing the assumption that 10% of all cables in the PAU are included. As the cable loadings are proportional to the total length of cable in the PAU, this treatment implicitly includes 10% of the length of the cable trays. A detailed breakdown of the calculation and related factors was added to the documentation.
5-36	HR-G1 HR-F2 HR-G3 HRA-B3 HRA-C1	The HRA was performed using the ERIN Screening approach provided in Figures 7-1 and 7-2 of the Fire PRA Model Development Analysis. Details are provided in the Appendix K table K-1. Use of this method is considered a screening approach and does not fully account for the Fire Specific PSFs and details of the accident sequences analyzed. HFEs based on the internal events (from HRA-B1) are translated in to the Fire PRA based on a simplified screening method using timing as the major element in revising the HEP. Specific review of the fire effects on sequence timing, Fire procedure guidance, the availability of cues (for which no instrumentation has been identified), or complexity of response has not been performed for the internal events actions. However, the simplified method generally provides a conservative assessment of the HEP for fire.	For the 2014 FPRA update, a detailed HRA treatment was used that was consistent with the FPIE PRA HRA methodology. It also considered uniquenesses associated with fire scenarios, such as adjusted timelines and use of different/multiple procedures. The HRA used the HRA Calculator consistent with the FPIE PRA.
5-37	HR-F2 HR-G4 HRA-A2 HRA-B2 HRA-B3 HRA-C1	Time available was based on the internal events PRA HRA. No new timing was included, other than for the new event TWC-XHE-ISOL. However, no basis for the 6 hour timing for this event was provided. Additionally, there is no discussion of the procedures used, location of the action, etc.	For the 2014 FPRA update, a detailed HRA treatment was used that was consistent with the FPIE PRA HRA methodology. It also considered uniquenesses associated with fire scenarios, such as adjusted timelines and use of different/multiple procedures. The HRA used the HRA Calculator consistent with the FPIE PRA.

TABLE A-4
RESOLUTION OF FPRA PEER REVIEW F&Os

F&O		F&O DESCRIPTION	RESOLUTION
5-38	HR-G6 HRA-C1	No Review of HEP Reasonableness appears to have been performed for the FPRA, taking into account the Fire Scenario being analyzed. Per HR-G6: Check the Consistency of the post-initiator HEP quantifications. REVIEW the HFEs and their final HEPs relative to each other to check their reasonableness given the scenario context, plant history, procedures, operational practices, and experience. - this is not documented or discussed in the FPRA documentation.	In the 2014 FPRA update, a reasonableness review of the HFEs and their HEPs was performed and documented and shown to be acceptable.
5-40	HR-G8 HRA-C1	Uncertainty factors for the JHEP values do not appear to have been included in the FPRA. Additionally, the new HEP added to the model (TWC-XHE-ISOL) did not have any uncertainty values added.	In the 2014 FPRA update, detailed HEP calculations, including uncertainty factors, have been developed with HRA Calculator for the 2014 FPRA update. The values of JHEPs were updated, but uncertainty factors were not calculated. Qualitative uncertainty was assessed and documented.
5-42	FSS-A5 FSS-C2 FSS-C6 FSS-D3	The scenarios analyzed in the HC FPRA do not appear to consider additional fire damage outside the immediate ZOI, other than for scenarios where full room burn-out is analyzed. For Scenarios involving a cabinet fire that ignite overhead cables or secondary combustibles, this may result in fire that either propagates outside of the ZOI or may produce a ceiling jet or HGL. In reviewing the several significant scenarios during the walkdown, this effect does not appear to be considered in the selection of damage targets.	In the 2014 FPRA update, the fire damage were revised to account for time-adjusted fire growth HRRs, potential for suppression, and growth to HGL or MCA. It also uses the latest industry data. Appropriate damage targets were included for each scenario.
5-43	FSS-A5 FSS-C4	The location of a transient event modeled in the FPRA is assumed on the floor when estimating the ZOI - based on walkdown of several scenarios and discussion with FPRA personnel. This results in a non-conservative ZOI for transient fires. Location of a transient fire would be dependent on the location and the transient package assumed. For most key areas, it is typically assumed the fire is a trash can, which would have its top a minimum several feet off the floor. Similarly, a trash bag fire would be located at the top of the trash bag, which would be 1-2 above the floor.	In the 2014 FPRA update, walkdowns were performed to re-verify transient sources and associated targets. The location of the transient for ZOI was measured at a height of 1-2 ft. above the floor.

TABLE A-4
RESOLUTION OF FPRA PEER REVIEW F&Os

F&O		F&O DESCRIPTION	RESOLUTION
5-46	FSS-A4	Hope Creek did not document the impact of fire on instrument air tubing. No discussion on sensitivity of tubing or piping to fire [e.g. brazed or soldered joints could melt these joints and depressurize the system] or size of breaks that could be impacting. No evaluation of instrument air failure mechanisms is included in the Fire PRA documentation. Reference: FPRA Report HC-PSA-21.05 Appendix A. It is noted that instrument air is generally not credited in the FPRA due to lack of cable data. However, additional tubing may be impacted (backup N2 bottles, etc), and failures associated with tubing damage may be different than a loss of instrument air.	In the 2014 FPRA update, a discussion of instrument air tubing was added to the documentation. Backup bottles are only credited inside containment (e.g., SRV backup pneumatic sources).
5-47	FSS-A5 FSS-C2	The generic ZOIs do not take into account time dependent increase in fire intensity related to cabinet to cabinet fire spread. In cases where multiple vertical sections of cabinets may be connected via openings or wireways consideration of fire spread between cabinets should be considered. This would produce increasing HRRs for the cabinet scenario over time which additionally changes the ZOI over time.	In the 2014 FPRA update, walkdowns confirmed that fire spread outside of the original ZOI does not occur for any risk-significant scenario; therefore, detailed modeling was not required. HRR and severity factors were calculated to postulate the development of HGL or MCA for each scenario.
5-48	FSS-D3	Use of CAFTA, FRANC and tools used in the Hughes Report provides reasonable assurance that the fire risk contribution of each unscreened physical analysis unit can be either bounded or realistically characterized. However, detailed fire Modeling is not performed for the significant fire scenarios or for fire scenarios where fire spread extends beyond the original ZOI as required by FSS-D3, CC II	See response to F&O 5-47.
5-49	FSS-D7	Multi-compartment analysis applied non-suppression for selected scenarios, based on generic data. Additionally, main control room abandonment includes non-suppression based on the 6850 models. No review of plant specific availability was performed.	In the 2014 FPRA update, non-suppression probabilities were re-calculated with credit for suppression and detection capabilities available for each scenario. This treatment was reviewed with plant fire engineers.

TABLE A-4
RESOLUTION OF FPRA PEER REVIEW F&Os

F&O		F&O DESCRIPTION	RESOLUTION
5-50	CF-A1 CF-B1	Option # 1 from NUREG/CR-6850 Tables 10-1 through 10-4 was used to determine circuit probabilities. The fire scenario notebook, Section 5.2 did not document the underlying assumptions such as, grounded design, non-complex MOV, have CPT, etc. The calculation did not account for any auxiliary or interlock circuits powered off a different source that can also spuriously operate the valves. The presence of auxiliary circuits could potentially increase the circuit failure probability.	In the 2014 FPRA update, a detailed discussion of the circuit failure analysis performed was added to the documentation, including underlying assumptions.
5-51	LE-F2 QU-D2 QU-F2 QU-D5 UNC-A1 FQ-D1 FQ-E1 FQ-F1	The Results of the FPRA CDF and LERF are presented in the Summary and Quantification Notebook, along with the importance measures. Top Cutsets are also presented. However, a consistency review and review of insignificant sequences or cutsets does not appear to have been performed.	In the 2014 FPRA update, a consistency review and review of insignificant sequences and cutsets was performed during the cutset reviews.
5-52	QU-E1 LE-F3 LE-G4 LE-G5 UNC-A1 FQ-E1 FQ-F1	Section 3.17 and 3.18 of the FPRA Summary and Quantification Analysis provides a discussion of assumptions and sources of uncertainty in the FPRA. However, the sources of uncertainty is not complete, and not fully discussed. See Appendix V of NUREG/Cr-6850 for an example of potential sources of uncertainty to be considered. Additionally, the limitations of the LERF analysis (as required by LE-G5) are not identified in the FPRA results.	In the 2014 FPRA update, all identified sources of uncertainty were included in the documentation.
6-4	FSS-G6	No quantification of risk associated with multicompartment fire scenarios performed. A screening was performed of PAUs due to impacts of multi-compartment fires. However, as noted in the conclusion in FPRA Report HC-PSA21.07, further evaluation to eliminate conservatisms assumed in the screening methodology is required. Qualitative assessment (CCI) is also not complete for MCA.	In the 2014 FPRA update, a complete MCA analysis was included in the FPRA.

TABLE A-4
RESOLUTION OF FPRA PEER REVIEW F&Os

F&O		F&O DESCRIPTION	RESOLUTION
6-5	FSS-E4 UNC-A2	The FPRA documents the results of a sensitivity on crediting (not damaging) the components whose cable locations are unknown (table 6.1) --- However, a sensitivity case where components whose cable locations are unknown but are assumed to not be damaged in certain compartment scenarios are damaged (failed) is not documented. References: A qualitative discussion of the uncertainty associated with the exclusion of Y3 cables is provided in Appendix D of HC-PSA-21.06. Table 6-1 shows that if cable selection was performed for all credited PRA equipment the CDF would decrease by a maximum of approximately 17%. Crediting the components whose cable locations are unknown was found to have a moderate impact on CDF quantitatively. This CDF reduction, however, is the maximum reduction achievable and it would be expected that the actual reduction would be less than this value since some unknown location cables would be expected to be impacted by fire events.	In the 2014 FPRA update, this sensitivity case was performed and documented.
6-10	FMU-B4	Section 4.5.5, Model Quantification, Review and Approval, in step 4.A., notes that 'some changes based on non-mandatory guidance in the ASME PRA standard may require at least a limited peer review per the ASME PRA standard.' However, this SR states that this is a 'shall' not a 'non-mandatory' requirement. Reference: ER-AA-600-1015, Fire Model PRA Update.	The interpretation of this step is that if the change is considered an upgrade based on the PRA standard SR description, then the limited peer review will be required. The use of “may” in this procedure step applies to the assessment in determining if the change meets the ASME PRA standard SR description of an upgrade.

A.2.7 PRA Quality Summary

Based on the above, the HCGS PRA is of sufficient quality and scope for this application. The modeling is detailed; including a comprehensive set of initiating events (transients, LOCAs, and support system failures) internal flood scenarios, system modeling, human reliability analysis and common cause evaluations. The HCGS PRA technical capability evaluations and the maintenance and update processes described above provide a robust basis for concluding that these PRA models are suitable for use in the risk-informed process used for this application.

A.2.8 Identification of Key Assumptions

The methodology employed in this risk assessment followed the EPRI guidance as previously approved by the NRC. The analysis included the incorporation of several sensitivity studies and factored in the potential impacts from external events in a bounding fashion. None of the sensitivity studies or bounding analysis indicated any source of uncertainty or modeling assumption that would have resulted in exceeding the acceptance guidelines. Since the accepted process utilizes a bounding analysis approach which is mostly driven by that CDF contribution which does not already lead to LERF, there are no identified key assumptions or sources of uncertainty for this application (i.e. those which would change the conclusions from the risk assessment results presented here).

A.3 SUMMARY

A PRA technical adequacy evaluation was performed consistent with the requirements of RG 1.200, Revision 2. This evaluation combined with the details of the results of this analysis demonstrates with reasonable assurance that the proposed extension to the ILRT interval for HCGS to fifteen years satisfies the risk acceptance guidelines in RG 1.174.

A.4 REFERENCES

[A.1] Regulatory Guide 1.200, *An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk Informed Activities*, Revision 2, March 2009.

[A.2] Boiling Water Reactors Owners' Group, *BWROG PSA Peer Review Certification Implementation Guidelines*, Revision 3, January 1997.

[A.3] American Society of Mechanical Engineers, *Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications*, ASME RA-S-2002, New York, New York, April 2002.

[A.4] U.S. Nuclear Regulatory Commission, *An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities*, Draft Regulatory Guide DG-1122, November 2002.

[A.5] HC-MSPI-001, MSPI BASIS DOCUMENT, Revision 7, March 29, 2012.

[A.6] ASME/American Nuclear Society, *Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications*, ASME/ANS RA-Sa-2009, March 2009.

[A.7] *Hope Creek Generating Station PRA Peer Review Report*, BWROG Final Report, May 2009.

[A.8] Electric Power Research Institute (EPRI), *Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals: Revision 2-A of 1009325*. EPRI TR-1018243, October 2008.

[A.9] Hope Creek Generating Station, Fire PRA Peer Review Report Using ASME/ANS PRA Standard Requirements, November 2010.

[A.10] HC-016 Self-Assessment of the Hope Creek PRA Against the Combined ASME/ANS PRA Standard Requirements Revision 1.

[A.11] Not Used.

[A.12] Probabilistic Risk Assessment (PRA) Peer Review Process Guidance (NEI 00-02) Rev. A3, dated March 20, 2000