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

Subject: Brunswick Steam Electric Plant, Unit Nos. 1 and 2
Renewed Facility Operating License Nos. DPR-71 and DPR-62
Docket Nos. 50-325 and 50-324
License Amendment Request to Revise Units 1 and 2 Technical Specification 5.5.12 for Permanent Extension of Type A and Type C Leak Rate Test Frequencies

Ladies and Gentlemen:

Pursuant to 10 CFR 50.90, Duke Energy Progress, LLC (Duke Energy), is requesting an amendment for the Brunswick Steam Electric Plant (BSEP), Unit Nos. 1 and 2. The proposed change revises Technical Specification 5.5.12, *Primary Containment Leakage Rate Testing Program*.

The enclosure provides a description and assessment of the proposed change. Attachments 1 and 2 to the enclosure provide the existing TS pages, for Units 1 and 2, respectively, marked to show the proposed change. Attachments 3 and 4 provide revised (i.e., typed) TS pages for Units 1 and 2, respectively. Attachment 5 provides existing Unit 1 TS Bases pages marked to show associated TS Bases changes and is provided for information only. Attachment 6 provide an evaluation of the risk significance of the proposed change.

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

In accordance with 10 CFR 50.91, Duke Energy is providing a copy of the proposed license amendment to the designated representative for the State of North Carolina.

This document contains no new regulatory commitments. Please refer any questions regarding this submittal to Mr. Art Zaremba, Director – Nuclear Fleet Licensing, at (980) 373-2062.

I declare, under penalty of perjury, that the foregoing is true and correct. Executed on February 27, 2019.

Sincerely,

William R. Gideon

MAT/mat

Enclosure:

Description and Assessment of the Proposed Change

Attachment 1: Proposed Technical Specification Changes (Mark-Up) - Unit 1
Attachment 2: Proposed Technical Specification Changes (Mark-Up) - Unit 2
Attachment 3: Revised (Typed) Technical Specification Pages - Unit 1
Attachment 4: Revised (Typed) Technical Specification Pages - Unit 2
Attachment 5: Proposed Technical Specification Bases Pages (Mark-Up) Unit 1 (For Information Only)
Attachment 6: BSEP Evaluation of Risk Significance of Permanent ILRT Evaluation

cc:

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EVALUATION OF THE PROPOSED CHANGE

SUBJECT: License Amendment Request to Revise Units 1 and 2 Technical Specification 5.5.12 for Permanent Extension of Type A and Type C Leak Rate Test Frequencies

1.0 SUMMARY DESCRIPTION

In accordance with 10 CFR 50.90, "Duke Energy Progress, LLC (Duke Energy) requests an amendment to Renewed Facility Operating License DPR-71 and DPR-62 for Brunswick Steam Electric Plant (BSEP), Unit No. 1 and Unit No. 2, respectively, to allow for permanent extension of the Type A and Type C leakage rate testing frequencies. The proposed change revises Units 1 and 2 Technical Specification (TS) 5.5.12, "Primary Containment Leakage Rate Testing Program," to reflect the following:

- Increases the existing Type A integrated leakage rate test (ILRT) program test interval from 10 years to 15 years in accordance with Nuclear Energy Institute (NEI) Topical Report (TR) NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J," Revision 3-A (i.e., Reference 2) and the conditions and limitations specified in NEI 94-01, Revision 2-A (i.e., Reference 3).
- Adopts an extension of the containment isolation valve (CIV) leakage rate testing (i.e., Type C) frequency from the 60 months currently permitted by 10 CFR 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors," Option B, to a 75-month frequency for Type C leakage rate testing of selected components, in accordance with NEI 94-01, Revision 3-A.
- Adopts the use of American National Standards Institute/American Nuclear Society (ANSI/ANS 56.8-2002, "Containment System Leakage Testing Requirements" (i.e., Reference 4).
- Adopts a more conservative allowable test interval extension of nine months, for Type A, Type B and Type C leakage rate tests in accordance with NEI 94-01, Revision 3-A.

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

This License Amendment Request (LAR) also proposes administrative changes to the exceptions in Units 1 and 2 TS 5.5.12. Two exceptions listed in the Units 1 and 2 TS 5.5.12 contain references to revisions and years of the ANSI/ANS 56.8 and NEI 94-01. Unit 1 and 2 TS exceptions 5.5.12.c reference NEI 94-01 Revision 0 (i.e., Reference 5) and Units 1 and 2 exceptions TS 5.5.12.f reference ANSI/ANS 56.8-1994 (i.e., Reference 6). With the approval of the proposed amendment, the referenced revision and year will no longer be the licensing basis for the program. The evaluation and continued use of these amendments is further described in Section 3.4.3.

2.0 DETAILED DESCRIPTION

BSEP Units 1 and 2 TS 5.5.12, "Primary Containment Leakage Rate Testing Program," each currently state, in part:

> A primary containment leakage rate testing program shall establish requirements to implement the leakage rate testing of the primary containment as required by 10 CFR

50.54(o) and 10 CFR 50, Appendix J, Option B as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, September 1995, as modified by the following exceptions:

a. The visual examination of concrete surfaces intended to fulfill the requirements of 10 CFR 50, Appendix J, Option B testing, will be performed in accordance with the requirements of and frequency specified by the ASME Section XI Code, Subsection IWL, except where relief has been authorized by the NRC.

b. The visual examination of the metallic shell, penetrations, and appurtenances intended to fulfill the requirements of 10 CFR 50, Appendix J, Option B, will be performed in accordance with the requirements of and frequency specified by the ASME Section XI Code, Subsection IWE, except where relief has been authorized by the NRC.

c. Following air lock door seal replacement, performance of door seal leakage rate testing with the gap between the door seals pressurized to 10 psig instead of air lock testing at P_a as specified in Nuclear Energy Institute Guideline 94-01, Revision 0.

d. Reduced duration Type A tests may be performed using the criteria and Total Time method specified in Bechtel Topical Report BN-TOP-1, Revision 1.

e. Performance of Type C leak rate testing of the hydrogen and oxygen monitor isolation valves is not required; and

f. Performance of Type C leak rate testing of the main steam isolation valves at a pressure less than P_a instead of leak rate testing at P_a as specified in ANSI/ANS 56.8-1994.

The proposed changes to BSEP Units 1 and 2 TS 5.5.12 will replace the reference to RG 1.163 with reference to NEI Topical Report NEI 94-01 Revisions 2-A and 3-A.

This LAR also proposes administrative changes to two of the exceptions in Units 1 and 2 TS 5.5.12. These two exceptions provided in TS 5.5.12.c and TS 5.5.12.f contain references to revisions and years of NEI 94-01 and ANSI/ANS 56.8. Specifically, 5.5.12.c references NEI 94-01 Revision 0 and TS 5.5.12.f references ANSI/ANS 56.8-1994. These two exceptions will be updated to reflect the appropriate document revisions, accordingly. With the approval of the proposed amendment, the referenced revision and year will no longer be the licensing basis for the program.

The proposed change revises the BSEP Units 1 and 2 TS 5.5.12 to read as follows (i.e., with recommended changes in **bold-type** for clarification purposes):

A primary containment leakage rate testing program shall establish requirements to implement the leakage rate testing of the primary containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in **NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J," Revision 3-A, dated July 2012, and the conditions and limitations specified in NEI 94-01, Revision 2-A, dated October 2008** as modified by the following exceptions:

a. The visual examination of concrete surfaces intended to fulfill the requirements of 10 CFR 50, Appendix J, Option B testing, will be performed in accordance with the

requirements of and frequency specified by the ASME Section XI Code, Subsection IWL, except where relief has been authorized by the NRC.

b. The visual examination of the metallic shell, penetrations, and appurtenances intended to fulfill the requirements of 10 CFR 50, Appendix J, Option B will be performed in accordance with the requirements of and frequency specified by the ASME Section XI Code, Subsection IWE, except where relief has been authorized by the NRC.

c. Following air lock door seal replacement, performance of door seal leakage rate testing with the gap between the door seals pressurized to 10 psig instead of air lock testing at P_a as specified in Nuclear Energy Institute Guideline 94-01, Revision **3-A**.

d. Reduced duration Type A tests may be performed using the criteria and Total Time method specified in Bechtel Topical Report BN-TOP-1, Revision 1.

e. Performance of Type C leak rate testing of the hydrogen and oxygen monitor isolation valves is not required; and

f. Performance of Type C leak rate testing of the main steam isolation valves at a pressure less than P_a instead of leak rate testing at Pa as specified in in ANSI/ANS 56.8-**2002**.

The marked-up TS pages for BSEP Units 1 and 2 TS 5.5.12 are provided in Attachments 1 and 2, respectively. The retyped pages of the BSEP TS pages for the BSEP Units 1 and 2 TS 5.5.12 are provided in Attachments 3 and 4, respectively.

The proposed changes to the TS Bases are provided in Attachment 5 for information only. Changes to the attached TS Bases pages will be incorporated in accordance with BSEP TS 5.5.10, "Technical Specifications (TS) Bases Control Program."

Attachment 6 contains the plant specific risk assessment conducted to support this proposed change. This risk assessment followed the guidelines of NRC RG 1.174, Revision 2 (i.e., Reference 7) and NRC RG 1.200, Revision 2 (i.e., Reference 29). The risk assessment concluded that increasing the ILRT on a permanent basis to one-in-fifteen-year frequency is considered to represent a very small change in the BSEP risk profile.

3.0 TECHNICAL EVALUATION

3.1 Description of Containment System

The reactor building encloses the drywell and the suppression chamber. Both the drywell and the suppression chamber consist of reinforced concrete pressure vessels with leak-tight steel liners on all inside surfaces. Welded seams on the steel liner are covered by channels intended for leak testing these welds. Where the test channel ports are covered with a pipe plug, the test channels provide a redundant primary containment barrier and are considered part of the primary containment boundary. All three structures are founded on a common reinforced concrete mat supported on a layer of dense sand which overlays limestone strata.

The drywell is composed of vertical right cylinders and truncated cones with inside diameters varying between 36 feet and 65 feet forming a configuration similar to the conventional steel containment "light bulb" shape. The overall height from the top of the foundation mat to the drywell head flange connection is approximately 111 feet. The 35 feet, 10-inch diameter steel

dome covering the top of the drywell is furnished with double gasketed flanges and is securely fastened to the reinforced drywell liner extension, which is in turn anchored to the top of the reinforced concrete portion of the drywell with 84 uniformly spaced pretensioned bolts. The flange detail includes provision for pressurizing the space between the two gaskets.

The lower cylindrical section of the drywell contains two large circular openings, each 10 feet in diameter. The openings are directly opposite each other. One opening, the personnel air lock, serves as a combination personnel air lock and equipment access hatch. The second opening, the equipment hatch, is used solely to install or remove equipment and is closed during operation with an internal bolted steel cover. Each opening has a steel liner sleeve welded to an insert plate in the drywell liner and anchored to the concrete at the junction of the drywell liner and the opening.

During operation, the personnel air lock is bolted to the 10 feet diameter penetration sleeve in the drywell. Entrance is gained through a series of two interlocking doors. The air lock is mounted on rails and when required for equipment access it can be unbolted and rolled away from the drywell providing a 10 feet diameter opening.

The Units 1 and 2 personnel air lock penetration sleeves have been modified by adding a concentric sleeve inside the existing liner sleeves. Each unit's concentric sleeves are circumferentially welded into place at both ends. An air gap of approximately one inch remains between the new and old penetration sleeve to provide for thermal expansion, as in the original design.

The equipment hatch opening is closed during operation by a steel cover which is bolted to an insert plate in the drywell liner. The insert plate is in turn anchored to the reinforced concrete. Since the equipment hatch opening is covered, it does not experience the thermal transients that the other large openings are subject to and therefore the felt layers were not required. The pressure loads on the hatch cover were lumped around the perimeter of the opening to maximize the reinforcing stresses.

The suppression chamber is a hollow reinforced concrete shell of rectangular cross-section encircling the lower portion of the drywell containment structure. The concrete encloses 16 continuous, inter-connected cylindrical sections 3/8-inch thick, that form a torus steel liner. The cross-sectional diameter of the suppression chamber is 29 feet and the major centerline of the torus is 109 feet. The suppression chamber is structurally independent of the drywell.

Eight 6 feet 4-inch diameter vent openings are uniformly spaced at 45-degree intervals in the lower conical section of the drywell. The vent openings are coincident with and connected to the eight respective vent openings in the suppression chamber. Each vent is enclosed by a steel liner sleeve that is welded to an insert plate in the drywell liner, and anchored to the reinforced concrete and the junction of the drywell liner and the vent line opening. The steel liner sleeves of the vents are also wrapped with felt, similar to the personnel airlock penetration sleeve, to allow for free thermal expansion.

3.1.1 Drywell and Suppression Chamber

The drywell consists of two vertical right cylinders jointed by two truncated conical sections with a solid cylindrical base pedestal. The top of the drywell is closed by a continuous steel dome, which is bolted to the top of the drywell.

The drywell pedestal is a 17-foot thick solid cylindrical concrete disk and contains top and bottom reinforcing over the total plan area. The top reinforcing grid consists of radially and circumferentially spaced bars. The circumferential bars are continuous closed circular hoops. The radial bars are terminated on the outside face of the pedestal by a 90-degree hook extending into the depth of the pedestal. Near the pedestal centerline, where concrete tensile stresses are minimum or in compression, the radial bars are terminated and lap-sliced with an orthogonal grid of reinforcing bars. The bottom pedestal reinforcing contains two orthogonal layers of reinforcing bars uniformly spaced over the full area of the pedestal. The bottom reinforcing grid is terminated in the concrete compression zone near the outside perimeter of the mat. In addition to the top and bottom reinforcing, a band of closed hoop bars, evenly spaced through the full depth of the pedestal, runs along the outside face. Pedestal shear reinforcing is provided through the depth in the form of bent Z bars inclined at an angle of 45 degrees.

The drywell wall reinforcing consists of circumferential closed hoops on each face along its full height, continuous meridional reinforcing on each face, diagonal seismic reinforcing on the outside face, and shear reinforcing.

The drywell openings described above have special reinforcing as discussed below. The closed hoop reinforcing bars are evenly grouped or banded above and below the openings. The continuous main meridional reinforcing, which would be interrupted by the openings, is grouped and bent or splayed around the openings to maintain the continuity of the reinforcing.

Supplemental reinforcing is placed around the openings in the areas left void of the meridional and hoop bars. Closed hoop rings are provided around the openings to accommodate stress concentration effects. Radial shear reinforcing consisting of hooked bars is placed around the large openings to accommodate transverse and popout shears.

Shear reinforcing is provided in the drywell wall in the form of inclined and horizontal hooked bars through the depth of the wall. A diagonal grind of reinforcing is provided at the outside face of the drywell wall to resist tangential (in plane) seismic shear.

The suppression chamber is structurally independent of the drywell containment and supported on the same foundation mat. A paper joint is provided between the bottom of the suppression chamber and the foundation mat to allow radial expansion of the suppression chamber. Vertical keys are provided along the outside perimeter of the drywell pedestal to allow independent, unrestrained expansion of the suppression chamber when subjected to symmetrical loading conditions. Under asymmetric loads the keys force the drywell and suppression chamber to respond as a single unit. The suppression chamber is reinforced with a single layer of continuous closed hoop reinforcing equally spaced around the perimeter of the liner. Meridional reinforcing in the form of closed rings is provided, and is placed radially to the centerline of the containment. Diagonal seismic reinforcing is located along the vertical faces of the suppression chamber. Additional reinforcing is provided in the top section of the suppression chamber for crack control.

The suppression chamber contains eight symmetrically located vent openings corresponding to the vent openings in the drywell. The main hoop reinforcing which would normally occur in the openings is banded above and below the openings. The meridional bars which would normally occur at these locations are grouped on either side. Reinforcing for areas left void by banding the main hoop and meridional reinforcing is provided by fill steel. Radial stirrups are provided around each vent opening to accommodate the transverse shears due to the openings.

3.2 Plant Operational Performance

During power operation, the primary containment atmosphere is inerted with nitrogen to ensure that no external sources of oxygen are introduced into containment. The containment inerting system is used during initial purging of the primary containment prior to power operation and provides a supply of makeup nitrogen to maintain primary containment oxygen concentration within TS limits. As a result, the primary containment is maintained at a slightly positive pressure during power operation. During power operation, instrument air system (i.e., nitrogen) leaks occur from pneumatically-operated valves inside primary containment which gradually pressurize the primary containment. Primary containment pressure is monitored in the control room. The primary containment atmosphere is periodically vented in order to maintain containment pressure within an acceptable operating range. This cycling of the primary containment pressure during operation amounts to a periodic integrated pressure test of the containment at a low differential pressure. Although this cycling does not challenge the structural and leak tight integrity of the primary containment system at post-accident pressure, it provides assurance that a gross containment leakage that may develop during power operation will be detected. This feature is a compliment to visual inspection of the interior and exterior of the containment structure for those areas that may be inaccessible for visual examination. In the event pressurization does not occur, a leakage path must be present. During power operation, drywell pressure is monitored from the control room and vented if pressure reaches 0.7 pounds per square inch (psi). Additionally, Engineering performs system monitoring and trending of overall drywell pressure during power operations to determine the health of the Containment Atmospheric Control (CAC) System.

3.3 Emergency Core Cooling System Net Positive Suction Head Analysis

Original plant Net Positive Suction Head (NPSH) calculations took no credit for containment (i.e., suppression chamber) pressure. As part of the 120 percent power uprate, the commitment was revised. Specifically, a 5-pound per square inch gauge (psig) credit for containment overpressure was established as acceptable for evaluating low pressure Emergency Core Cooling System (ECCS) pump NPSH. The 120 percent power uprate was approved by the NRC on May 31, 2002 (i.e., Reference 53).

3.3.1 Short Term NPSH Requirements

For short term (i.e. 0 to 600 seconds) post-loss of coolant accident (LOCA) operation, no operator action is credited and, as a result, the residual heat removal (RHR) and core spray (CS) pumps are assumed to be at maximum flow conditions. For RHR, expected flow is 10,500 gallons per minute (gpm) per pump and 21,000 gpm per loop. For CS, expected flow is 6,700 gpm. The peak suppression pool temperature prior to assumed operator action (i.e. short term) was found to be 169.1 degrees Fahrenheit (°F). This is adequate such that no credit for containment overpressure is needed for the short-term conditions.

3.3.2 Long Term NPSH Requirements

For long-term (i.e., greater than 600 seconds) post-LOCA operation, operator action to throttle the RHR and CS pumps is assumed. As such, the assumed pump flows are 5,750 gpm per RHR pump (i.e., 11,500 gpm loop flow) and 5,000 gpm for the CS pumps. The 120 percent power uprate analysis was also performed both with and without crediting containment spray. The case that did not credit containment spray produced the peak temperature response of 207.7°F with a corresponding pressure of 25.5 psig. However, the case that credited

containment spray produced a slightly lower temperature profile (i.e., a 206.8°F peak) and a much lower pressure profile with an 11.3 psig peak. For conservatism, the NPSH calculations were performed based on the containment spray case, with the containment spray temperature profile increased by 0.9°F such that the peak temperature equaled that of the no spray case.

The maximum expected RHR flow was found to be 21,000 gpm or 10,500 gpm per pump.

This analysis demonstrated that runout for two-pump operation does not occur even in the worst case of discharge through a broken loop. Single pump runout was not evaluated because single pump operation implies loss of one pump which is an additional failure over-and-above the failure of the discharge valve to close.

Using the conservative profile discussed above, the NPSH parameters were determined for bounding evaluations. For the period of interest, the maximum required overpressure needed to ensure NPSH is 2.65 psig, with 11.3 psig containment overpressure available. In all cases, the available containment overpressure is in excess of three times the amount required to ensure adequate NPSH. To ensure sufficient margin exists to address potential future issues, the submittal for 120 percent power uprate requested that containment overpressure of up to 5.0 psig be credited for calculating ECCS pump NPSH margins. The NRC approved the request.

The High-Pressure Coolant Injection (HPCI) pumps are designed to operate continuously with suppression pool temperatures up to 140°F, normal suction is taken from the outside condensate storage tank. In the event of a failure of this storage tank, alternate suction exists to the suppression pool. Since the suppression pool temperature (SPT) will exceed 140°F during a design basis accident (DBA), the HPCI system has been designed to operate for short periods of time up to a temperature of 170°F. Because the reactor system depressurizes very rapidly after a DBA, the HPCI system will not operate for any significant length of time, nor is it required to mitigate the effects of the accident. Sufficient NPSH is available to the HPCI pump for these temperatures.

3.3.3 Containment Accident Pressure Evaluation

In general, core damage frequency (CDF) is not significantly impacted by an extension of the ILRT interval; however, plants that rely on containment accident pressure (CAP), also referred to as containment overpressure (COP), for NPSH for ECCS injection for certain accident sequences may experience an increase in CDF. BSEP credits CAP in support of ECCS performance to mitigate design basis accidents; a loss of CAP may lead to degraded or a total loss of ECCS pump flow. Therefore, a detailed analysis was performed in BSEP Calculation 54011-CALC-01 (i.e., Attachment 6 to this submittal) to quantify the potential effect on CDF. The following provides an overview and summary of the analysis and the results.

Per the EPRI 1009325 guidance (i.e., Reference 8):

> In the case where containment overpressure may be a consideration, plants should examine their ECCS NPSH requirements to determine if containment overpressure is required (and assumed to be available) in various accident scenarios. Examples include the following:
>
> - LOCA scenarios where the initial containment pressurization helps to satisfy the NPSH requirements for early injection in BWRs or PWR sump recirculation

- Total loss of containment heat removal scenarios where gradual containment pressurization helps to satisfy the NPSH requirements for long-term use of an injection system from a source inside of containment (for example, BWR suppression pool).

In a design basis LOCA event, for long-term (i.e., greater than 600 seconds) post-LOCA operation, up to 5.0 psig of CAP is credited at BSEP to ensure adequate NPSH margin (i.e., NPSH available minus NPSH required); for short-term, less than 600 seconds, operation; the NPSH margin is sufficient and no credit for CAP is needed. Therefore, LOCA sequences must be analyzed for an impact from a loss of CAP. In the Probabilistic Risk Assessment (PRA), all LOCA sequences are considered, which includes all modeled Reactor Coolant System (RCS) pipe breaks and transient-induced LOCAs (e.g., inadvertent safety relief valve (SRV) opening without closure).

Further, the EPRI guidance states

- If either of these cases is susceptible to whether or not containment overpressure is available (or other cases are identified), then the PRA model should be adjusted to account for this requirement.

The BSEP PRA also credits CAP for the intermittent use of long-term injection systems with suction from the suppression pool for transient sequences where suppression pool cooling is failed; this function requires an elevated pressure in containment to support NPSH to the ECCS. Therefore, transient sequences must be analyzed for an impact from a loss of CAP.

The effect of a loss of CAP on CDF was analyzed for both internal and external events.

3.3.4 Loss of CAP Analysis

A loss of CAP may lead to failure of the low pressure ECCS, RHR and CS, due to inadequate NPSH available to support required pump flow. Suppression pool cooling (SPC) can be initiated to lower the SPT and increase the available NPSH. In other words, CAP is not required if SPC is successfully established in time to preclude SPT from exceeding the value where available NPSH would decrease below that required to support pump flow. If SPC is not initiated in time or fails, the intermittent use of the low pressure ECCS for post-vent, long-term injection for transient scenarios credits elevated containment pressure to function. Given the possible existence of a pre-existing leak in containment evaluated in this risk analysis, these long-term injection sources may be failed if SPC is not successful.

The approach to modeling the risk impact due to the potential loss for CAP given a pre-existing leak involved two model changes:

- First, the PRA timing for the operator actions to establish SPC was confirmed adequate to preclude the need for CAP. Timing was verified for all accident sequences where low pressure ECCS are credited, and, if the existing operator action timing was not adequate to preclude the need for CAP, then the model was adjusted to include the required (i.e., shorter) operator action timing. The details are discussed below.

- Second, the PRA model was adjusted to ensure low pressure ECCS were failed if SPC fails, which models the impacts of inadequate NPSH given the pre-existing leak, no SPC, but sequences where containment venting succeeds and long-term low-pressure injection is required.

MAAP Analyses Inputs

In order to establish the operator action timing for initiating SPC in time to preclude the need for CAP for low pressure ECCS NPSH, existing and new MAAP analyses cases were utilized.

MAAP analyses supporting the Fire PRA were performed in order to analyze the effect of a loss of CAP due to multiple spurious operations (MSOs) that result in an un-isolated containment on the low pressure ECCS. Review of these cases determined they are applicable/bounding for transient sequences in the BSEP PRA because the un-isolated containment ensures no CAP can build to support low pressure ECCS NPSH, and the Fire PRA is composed of mostly transient risk. According to the Fire PRA MAAP analysis, an SPT of 192°F will degrade RHR pump flow and an SPT of 202°F will degrade the CS flow. It was determined that if SPC is initiated when the SPT reaches 185°F, the SPT will remain below these criteria. Per the Fire PRA MAAP results, the most limiting timing for initiating SPC with an un-isolated containment is 3.69 hours. The operator action to initiate SPC following a non-LOCA in the PRA modes is OPER-SPCE, which has a timing of 3.8 hours. This small difference in time leads to no change in the Human Error Probability (HEP) value, and thus no change in risk. Therefore, the modeled operator action to initiate SPC for a transient sequence is considered appropriate for the loss of CAP analysis.

Existing MAAP analyses were applicable to transient risk in the BSEP PRA, but do not apply to RCS pipe break LOCA conditions and the heatup timing of the suppression pool in LOCA sequences. To establish the timing required to initiate SPC given an RCS pipe break LOCA to preclude the need for CAP, MAAP runs were performed for small, medium, and large LOCA scenarios for the CAP analysis using similar methodology to the Fire PRA MAAP analyses discussed above. Per the BSEP Level 2 analysis, a 2-inch diameter opening in containment equates to 30 - 35 wt.%/day, and an opening size of 3.5-inches equates to 100 wt.%/day. Per Section 5.2.2 of Attachment 6 of this submittal, allowable containment leakage, L_a, is 0.5 wt.%/day; therefore, 100 L_a is 50 wt.%/day, which approximately equates to an opening size of 2.5-inches in diameter. Therefore, the loss of CAP LOCA analyses assume a containment opening size of 2.5 inches; minor changes in the size of the opening have little impact on the results.

The results of the CAP analysis MAAP runs indicate that initiating SPC at 2.4 hours for small and medium LOCAs and 1.75 hours for large LOCAs prevents reaching the SPT criterion. Using these timings, two detailed Human Failure Event (HFEs) were created for initiating SPC with loss of CAP, one for small and medium LOCAs and one for large LOCAs. The HFEs were based off operator action OPER-SPC, which is the operator action to initiate SPC following a LOCA. The BSEP PRA model was adjusted to utilize these HFEs for LOCA scenarios to model the time in which SPC must be initiated to preclude the need for CAP to support low pressure ECCS NPSH.

Model Adjustment

With the timing to initiate SPC to preclude the need for CAP to support low pressure ECCS NPSH established via the MAAP analyses, the Unit 1 and Unit 2 models (i.e., Internal and External Events) were revised. The revised CAP analysis models include failure of the low pressure ECCS (i.e., RHR and CS) given a pre-existing leak in containment and failure to initiate SPC in time to preclude the need for CAP to support low pressure ECCS NPSH (i.e., new HFEs) in all applicable sequences in each model. For the purposes of this risk assessment, internal events models are the full-power internal events and internal flooding PRA

models; external event models are Fire PRA and High Winds PRA models. The CAP analysis Unit 1 and Unit 2 models were quantified to estimate the change in CDF from the increased likelihood of pre-existing leaks given the ILRT surveillance frequency change.

The pre-existing leak basic event probability was varied from 2.30E-03 (i.e., probability of a 3b leak based on an ILRT interval of 3-in-10 years) to 1.15E-02 (i.e., probability of a 3b leak based on the ILRT interval of 1-in-15 years) and the CDF for each surveillance frequency was estimated. The ΔCDF was estimated as the difference between the two surveillance frequency cases. The ΔCDF was also estimated for the 1-in-10 years ILRT interval by changing the pre-existing leak basic event probability to 7.67E-03.

<u>Quantification Results</u>

The results of the analysis are provided below and summarized in Table 5-20 for Unit 1 and Table 5-21 for Unit 2 of Attachment 6 of this submittal.

The CDF increase due to a loss of CAP due to the ILRT extension to 1-in-15 years from 3-in-10 years is estimated to be 1.61E-08/year for Unit 1 and 1.54E-08/year for Unit 2. This ΔCDF was assumed equal to the change in large early release frequency (ΔLERF) from CAP and added to the EPRI Class 3b frequency and included in the results provided in Section 6.0 and in the sensitivities performed in Section 5.3 of Attachment 6 of this submittal. The CDF increase due to a loss of CAP due to the ILRT extension to 1-in-10 years from 3-in-10 years is estimated to be 9.37E-09/year for Unit 1 and 9.01E-09/year for Unit 2.

Similarly, for High Wind events, the pre-existing leak basic event probability was varied from 2.30E-03 to 1.15E-02, which causes a delta of 6.41E-08 for Unit 1 and 6.31E-08 for Unit 2. This ΔCDF was assumed equal to ΔLERF from CAP and added to the EPRI Class 3b frequency for High Winds events in the external events analysis. The CDF increase due to a loss of CAP due to the ILRT extension to 1-in-10 years from 3-in-10 years is estimated to be 3.75E-08/year for Unit 1 and 3.69E-08/year for Unit 2.

For Fire events, the quantification showed no increase in CDF due to the pre-existing leak in containment; therefore, there is a negligible change in CDF due to the ILRT extension.

For seismic events, a qualitative and bounding CAP analysis was performed. Since BSEP credits the use of RHR and CS for long-term intermittent injection for transient sequences, there may be some impact to seismic CDF due to a loss of CAP. Generally, seismic risk is dominated by failure of key plant structures and key plant systems due to seismic motion which exceeds the capacity of key structures and systems. Failure of key structures (e.g., containment building, reactor building, etc.) are typically assumed to lead straight to core damage; and therefore, a loss of CAP will have no impact. It is common to treat equipment of the same type at the same elevation as being failed due to the seismic event, so seismic events that only fail some low pressure ECCS pumps are much more likely than seismic events that only fail some low pressure ECCS pumps while others survive; a loss of CAP will have no impact on scenarios where all ECCS pumps are failed. Furthermore, a loss of CAP will have no impact on station blackout (SBO) scenarios; since the ECCS pumps will be failed due to a loss of power. A loss of CAP may impact seismic scenarios where a key structure is not failed and the low pressure ECCS pumps are available. As a bounding estimate, the ΔCDF for seismic scenarios is assumed proportional to the ΔCDF for Internal Events. This is bounding because the predominant contributor to the increase due to a loss of CAP for Internal Events is LOCA sequences and seismic events are far more likely to lead to key structure and system failures or

SBO sequences than LOCA sequences. This leads to a seismic ΔCDF of 3.02E-08 for Unit 1 and 3.10E-08 for Unit 2. These ΔCDF sequences were assumed equal to ΔLERF from CAP and added to the EPRI Class 3b frequency for seismic events in the external events analysis. The CDF increase due to a loss of CAP due to the ILRT extension to 1-in-10 years from 3-in-10 years is estimated to be 1.76E-08/year for Unit 1 and 1.81E-08/year for Unit 2.

RG 1.174 defines very small changes in CDF as resulting in increases of CDF less than 1.0E-06/year. Per the analysis, the change CDF due to a loss of CAP and the ILRT extension is considered "very small".

3.3.5 Key Assumptions and Sources of Uncertainty

Key assumptions or sources of uncertainty for the loss of CAP analysis are the following:

- No credit is given for alignment of CS to the Condensate Storage Tank (CST), a source outside containment. Procedures are in place to align CS to the CST. Aligning the CS pumps to the CST would significantly reduce CDF for single unit events. Not crediting CS alignment to the CST is conservative.

- Another source of uncertainty is whether or not a "large" "early" release would occur in a loss of NPSH scenario. This uncertainty is addressed with the CAP related assumption that loss of low pressure injection (i.e., CS and RHR) due to a pre-existing leak and loss of SPC leads to a large early release. This may be a conservative assumption. Loss of inventory make-up may result in a delayed "non-Large" release, for which there would be adequate time for evacuation.

- Diverse and Flexible Coping Strategies (FLEX) is not modeled in the External Events models; and therefore, was not credited in the External Events loss of CAP analysis. Crediting FLEX would reduce the increase due to a loss of CAP for High Winds events, since FLEX is a separate form of late injection that would likely be available even if the intermittent long-term use of the low pressure ECCS systems was failed due to a loss of CAP. Similarly, FLEX would reduce the risk from seismic events given a loss of CAP; however, seismic events were not quantitatively analyzed in the CAP analysis.

- It is assumed the low pressure ECCS pumps will fail when the SPT criteria is met. The reduction in NPSH may not lead to immediate failure of the pumps, and instead, may only degrade the flow. Furthermore, it is noted that industry testing and analysis indicate that ECCS pumps used in BWR 3/4 plants are capable of adequate short term (i.e., approximately 24 hour) operation well below the manufacturer's recommended design NPSH (e.g., 65% of the specified NPSH limit for Browns Ferry as documented in NUREG/CR-2973 (i.e., Reference 9)). Therefore, additional margin exists beyond that reflected in the MAAP calculations.

- MAAP is known to have some modeling deficiencies (e.g., potential for reverse flow not modeled) for Large LOCA scenarios. These deficiencies only impact results in the early portion of the run (i.e., approximately first three minutes) prior to core recovery. These deficiencies do not impact the ILRT MAAP calculation results because the peak torus temperature is reached hours into each run.

3.4 Justification for the TS 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 surveillance of reactor containment penetrations and isolation valves are performed so that proper maintenance and repairs are made during the service life of the containment and those systems and components penetrating primary containment. The limitation on containment leakage provides assurance that the containment would perform its design function following an accident up to and including the plant DBA. Appendix J identifies three types of required tests: 1) Type A tests, intended to measure the primary containment overall integrated leakage rate; 2) Type B tests, intended to detect local leaks and to measure leakage across pressure-containing or leakage limiting boundaries (other than valves) for primary containment penetrations, and; 3) Type C tests, intended to measure CIV leakage rates. Type B and C tests identify the vast majority of potential containment leakage paths. Type A tests identify the overall (i.e., integrated) containment leakage rate and serve to ensure continued leakage integrity of the containment structure by evaluating those structural parts of the containment not covered by 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 (i.e., Reference 1) was issued. The RG endorsed NEI 94-01, Revision 0, (i.e., 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, (i.e., Reference 10) and Electric Power Research Institute (EPRI) TR-104285 (i.e., Reference 11) both of which showed that the risk increase associated with extending the ILRT surveillance interval was very small. In addition to the 10-year ILRT interval, provisions for extending the test interval an additional 15 months were considered in the establishment of the intervals allowed by RG 1.163 and NEI 94-01, but that this extension of interval "should be used only in cases where refueling schedules have been changed to accommodate other factors."

In 2008, NEI 94-01, Revision 2-A (i.e., Reference 3), was issued. This document describes an acceptable approach for implementing the optional performance-based requirements of Option B to 10 CFR 50, Appendix J, subject to the limitations and conditions noted in Section 4.0 of the NRC Safety Evaluation Report (SER) on NEI 94-01. NEI 94-01, Revision 2-A, includes provisions for extending Type A ILRT intervals to up to 15 years and incorporates the regulatory positions stated in RG 1.163 (i.e., 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 (i.e., Reference 2), was issued. This document describes an acceptable approach for implementing the optional performance-based requirements of Option B to 10 CFR 50, Appendix J and includes provisions for extending Type A ILRT intervals to up to 15 years. NEI 94-01 has been endorsed as an acceptable methodology for complying with the provisions of 10 CFR Part 50, Appendix J, Option B, by RG 1.163 and NRC SERs dated June 25, 2008, and June 8, 2012 (i.e., References 1, 12, and 13, respectively). The regulatory positions stated in RG 1.163 as modified by References 10 and 11 are incorporated in this document. It delineates a performance-based approach for determining Type A, Type B, and Type C containment leakage rate surveillance testing frequencies. Justification for extending test intervals is based on the performance history and risk insights. Extensions of Type B and Type C test intervals are allowed based upon completion of two consecutive periodic as-found tests where the results of each test are within a licensee's allowable administrative limits. Intervals may be increased from 30 months up to a maximum of 120 months for Type B tests (i.e., except for containment airlocks) and up to a maximum of 75 months for Type C tests. If a licensee considers extended test intervals of greater than 60 months for Type B or Type C tested components, the review should include the additional considerations of as-found tests, schedule and review as described in NEI 94-01, Revision 3-A, Section 11.3.2.

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

> Section 9.2.3, NEI TR 94-01, Revision 2, states, "Type A testing shall be performed during a period of reactor shutdown at a frequency of at least once per 15 years based on acceptable performance history." However, Section 9.1 states that the "required surveillance intervals for recommended Type A testing given in this section may be extended by up to 9 months to accommodate unforeseen emergent conditions but should not be used for routine scheduling and planning purposes." The NRC staff believes that extensions of the performance-based Type A test interval beyond the required 15 years should be infrequent and used only for compelling reasons. Therefore, if a licensee wants to use the provisions of Section 9.1 in TR NEI 94-01, Revision 2, the licensee will have to demonstrate to the NRC staff that an unforeseen emergent condition exists.

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

> Consistent with standard scheduling practices for TS 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.

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

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

3.4.2 Current BSEP Primary Containment Leakage Rate Testing Program Requirements

10 CFR 50, Appendix J was revised, effective October 26, 1995, to allow licensees to choose containment leakage testing under either Option A, "Prescriptive Requirements," or Option B, "Performance-Based Requirements." On February 1, 1996, the NRC approved TS Amendment 181 for BSEP Unit 1 and Amendment 213 for BSEP Unit 2 (i.e., Reference 14) authorizing the implementation of 10 CFR 50, Appendix J, Option B for Types A, B and C tests.

Current Units 1 and 2 TS 5.5.12 requires that a program be established to comply with the containment leakage rate testing requirements of 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B. The program is required to be in accordance with the guidelines contained in RG 1.163. RG 1.163 endorses, with certain exceptions, NEI 94-01, Revision 0 (i.e., 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 rather than using test intervals specified in ANSI/ANS 56.8-1994 (i.e., Reference 6). NEI 94-01, Section 11.0 refers to Section 9, which states that Type A testing shall be performed during a period of reactor shutdown at a frequency of at least once per ten years based on acceptable performance history. Acceptable performance history is defined as completion of two consecutive periodic Type A tests where the calculated performance leakage was less than $1.0L_a$, where L_a is the maximum allowable leakage rate at design pressure. Elapsed time between the first and last tests in a series of consecutive satisfactory tests used to determine performance shall be at least 24 months.

Adoption of the Option B performance-based containment leakage rate testing program altered the frequency of measuring primary containment leakage in Types A, B, and C tests but did not alter the basic method by which Appendix J leakage testing is performed. The test frequency is based on an evaluation of the "as found" leakage history to determine a frequency for leakage testing which provides assurance that leakage limits will not be exceeded. The allowed frequency for Type A testing as documented in NEI 94-01 is based, in part, upon a generic evaluation documented in NUREG-1493 (i.e., Reference 10). The evaluation documented in NUREG-1493 includes a study of the dependence or reactor accident risks on containment leak tightness for differing types of containment types, including a pressure suppression containment similar to the BSEP containment structure. NUREG-1493 concludes in Section 10.1.2 that reducing the frequency of Type A tests from the original three tests per 10 years to one test per 20 years was found to lead to an imperceptible increase in risk. The estimated increase in risk

is very small because ILRTs identify only a few potential containment leakage paths that cannot be identified by Types B and C testing, and the leaks that have been found by Type A tests have been only marginally above existing requirements. Given the insensitivity of risk to containment leakage rate and the small fraction of leakage paths detected solely by Type A testing, NUREG-1493 concludes that increasing the interval between ILRTs is possible with minimal impact on public risk.

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

February 1, 1996

The NRC issued Amendment Nos. 181 and 213, which modified Units 1 and 2 TS 5.5.12, respectively, to allow the use of 10 CFR Part 50, Appendix J, Option B, Performance-Based Containment Leakage Rate Testing. (i.e., Reference 14)

March 6, 2002

The NRC issued Amendment No. 216, which modified Unit 1 TS 5.5.12 to allow for a one-time increase in the BSEP, Unit 1 Type A, ILRT for no more than 3 years, 2 months. (i.e., Reference 15)

November 21, 2002

The NRC issued Amendment No. 250, which modified Unit 2 TS 5.5.12 to allow for a one-time increase to the BSEP, Unit 2 Type A, ILRT for no more than 2 years, 2 months. (i.e., Reference 16)

March 9, 2005

The NRC issued an exemption from the requirements of 10 CFR Part 50, Appendix J to exclude the main steam isolation valve (MSIV) leakage from the overall integrated leakage rate test measurements required by Section III.A of Appendix J, Option B. (i.e., Reference 17)

February 8, 2006

The NRC issued Amendment No. 238 and Amendment No. 266, which revised Units 1 and 2 TS 5.5.12, respectively, to remove an exemption that allowed for compensation of flow meter instrument inaccuracies in accordance with the guidance document ANSI/ANS 56.8-1987, rather than meeting the instrument accuracy requirements in ANSI/ANS 56.8-1994. (i.e., Reference 18)

March 2, 2006

The NRC issued Amendment No. 239 and Amendment No. 267, for Units 1 and 2, respectively, which revised Surveillance Requirement 3.6.1.3.9 to increase the allowable MSIV leakage rate. Specifically, the limit was revised from an allowable leakage rate of less than or equal to 11.5 standard cubic feet per hour scfh through each MSIV to less than or equal to 100 scfh through each main steam line (MSL) with the combined leakage of the four MSLs being less than or equal to 150 scfh. (i.e., Reference 19)

February 8, 2008

The NRC issued Amendment No. 245 and Amendment No. 273, which revised Units 1 and 2 TS 5.5.12, respectively to allow the required Appendix J visual inspections to be performed in accordance with the ASME Boiler and Pressure Vessel (B&PV) Code, Section XI, Subsections IWE and IWL. (i.e., Reference 20)

3.4.3.1 Continued Acceptability of Units 1 and 2 TS 5.5.12.a, b, d and e.

Units 1 and 2 Exceptions TS 5.5.12.a and TS 5.5.12.b

By letter dated February 8, 2008, the NRC issued Amendment No. 245 and Amendment No. 273 which revised Units 1 and 2 TS 5.5.12, respectively to allow the required Appendix J visual inspections to be performed in accordance with the ASME BPV Code, Section XI, Subsections IWE and IWL. (i.e., Reference 20)

Units 1 and 2 TS Exception 5.5.12.d

By letter dated December 9, 1983, the NRC provided correspondence to BSEP stating that the use of Bechtel Topical Report BN-TOP-1, Revision 1, "Testing Criteria for Integrated Leakage Rate Testing of Primary Containment Structures for Nuclear Power Plants," had been previously approved and therefore offered no objection for its use for ILRTs at BSEP. Subsequently, by letter dated August 4, 1989, the NRC approved Amendment Nos. 136 and 166 for BSEP Units 1 and 2 to delete the requirement to use only the mass point method for Type A containment ILRTs permitted by Appendix J. (i.e., References 21, 22)

Units 1 and 2 TS Exception 5.5.12.e

By letter dated May 12, 1987, the NRC issued an exception from the requirements of 10 CFR 50, Appendix J which revised the BSEP Units 1 and 2 TS to exempt the hydrogen/oxygen monitor isolation valves from Type C testing. (i.e., Reference 23)

NEI 94-01, Revisions 2-A and 3-A, Section 1.1 state, in part,

> Generally, a FSAR (Final Safety Analysis Report) describes plant testing requirements, including containment testing. In some cases, FSAR testing requirements differ from those of Appendix J. In many cases, Technical Specifications were approved that incorporated exemptions to provisions of Appendix J. Additionally, some licensees have requested and received exemptions after their Technical Specifications were issued. The alternate performance-based testing requirements contained in Option B of Appendix J will not invalidate such exemptions. However, any exemptions to the provisions of 10 CFR 50, Appendix J to be maintained in force as part of the Containment Leakage Testing Program should be clearly identified as part of the plant's program documentation.

By letter dated June 25, 2008, the NRC issued the Final Safety Evaluation Report (SER) for NEI 94-01, Rev. 2, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J" and EPRI Report Number 1009325, Rev. 2, August 2007, "Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals." The SER states,

> If the exemptions were issued after the Technical Specifications were approved, when the licensee amends the TS requirements to the new test interval (for Type A, Type B or

Type C tests), it should explicitly describe which exemptions the licensee wants to continue with and which exemptions it will not use during the implementation of the new test intervals. This information should be part of the TS amendment request. The NRC staff requests that this section be clarified to state that this approach is acceptable provided the NRC has a chance to review the licensee's choice, as part of the TS amendment.

Conclusion:

This LAR does not change the Units 1 and 2 TS exceptions 5.5.12.a, b, d and e. Therefore, BSEP will continue to use the provisions of Unit 1 and 2 TS exceptions 5.5.12.a, b, d and e as written.

3.4.3.2 Continued Acceptability of Units 1 and 2 TS Exceptions 5.5.12.c and f with Minor Administrative Changes.

TS Exception 5.5.12.c

By letter dated November 23, 1977, the NRC issued Amendments No. 12 and 39 for BSEP Units 1 and 2 to Operating Licenses revising Standard Technical Specifications (STS) for Unit 1 and incorporating similar STS for Unit 2 (i.e., Reference 24). The plants original TS required testing of the Personnel Airlock seals at 10 psig. This testing procedure was changed in 1977 to 49 psig to conform to Appendix J criteria. With the issuance of the STS, the test pressure was changed back to 10 psig in conformance with the General Electric STS.

TS exception 5.5.12.c allows for testing of the airlock door seals at 10 psig in lieu of P_a, as specified in NEI 94-01, following airlock door seal replacement. This exception specifically references Revision 0 to NEI 94-01. Section 10.2.2.1 (i.e., fourth paragraph) of NEI 94-01 Revision 0 states,

> Door seals are not required to be tested when containment integrity is not required, however, they must be tested prior to reestablishing containment integrity. Door seals shall be tested at P_a, or at a pressure stated in the plant Technical Specifications.

As part of the proposed change, BSEP will incorporate NEI 94-01, Revision 3-A by reference into TS 5.5.12. The wording in NEI 94-01 Revision 3-A Section 10.2.2.1 regarding airlock door seal testing remains the same as in Revision 0. Therefore, TS exception 5.5.12.c will be revised to read,

> Following air lock door seal replacement, performance of door seal leakage rate testing with the gap between the door seals pressurized to 10 psig instead of airlock testing at P_a, as specified in Nuclear Energy Institute Guideline 94-01, Revision 3-A.

TS Exception 5.5.12.f

By letter dated November 8, 1977 (i.e., Reference 25), the NRC issued an exception from the requirements of Section III.C.2 of 10 CFR 50, Appendix J. This exception allowed BSEP to perform the Type C LLRT of the main steam isolation valves at a pressure of 25 psig instead of P_a (i.e., 49 psig).

TS exception 5.5.12.f allows for testing of the MSIVs at a pressure less than P_a, instead of leak rate testing at P_a. This exception specifically references ANSI/ANS 56.8-1994. ANSI/ANS 56.8-1994 Section 3.3.2 states,

> Types B and C tests shall be conducted at a differential pressure of not less than P_{ac} [containment accident pressure], except on airlock door seals, which may have a lower pressure specified in the plant's licensing basis. When a higher differential pressure results in increased sealing, such as a check valve, the differential pressure shall not exceed 1.1 P_{ac}.

As part of the proposed change, BSEP will incorporate NEI 94-01 Revision 3-A by reference into TS 5.5.12. NEI 94-01 Revision 3-A requires performance of integrated and local leakage rate testing in accordance with ANSI/ANS 56.8-2002. The wording in ANSI/ANS 56.8-2002 regarding the test pressure for Type B and C tests remains the same as in the 1994 edition of the ANSI standard. Therefore, TS exception 5.5.12.f will be revised to read,

> Performance of Type C leak rate testing of the main steam isolation valves at a pressure less than P_a instead of leak rate testing at P_a as specified in ANSI/ANS 56.8- 2002.

<u>Conclusion</u>:

The proposed changes to TS Exceptions 5.5.12.c and f are administrative in nature, and, therefore, do not change the requirements or performance of the Types B and C leakage testing.

<u>3.4.4 Integrated Leakage Rate Testing History (ILRT)</u>

As noted previously, BSEP TS 5.5.12 currently requires Types A, B, and C testing in accordance with RG 1.163, which endorses the methodology for complying with Option B. Since the adoption of Option B, the performance leakage rates are calculated in accordance with NEI 94-01, Section 9.1.1 for Type A testing. Tables 3.4.4-1 and 3.4.4-2 lists the past Periodic Type A ILRT results for BSEP Units 1 and 2, respectively.

Table 3.4.4-1 BSEP Unit 1 Type A Testing History

Test Date	95% Upper Confidence Limit (wt.%/day)	As-Found Leakage (wt.%/day)	Acceptance Criteria (wt.%/day)	As-Left Leakage (wt.%/day)	Acceptance Criteria (0.75La) (wt.%/day)	Performance Leakage Rate (wt.%/day)	Acceptance Criteria (La) (wt.%/day)
9/2/1976	0.191	0.191	0.375	0.191	0.375	N/A	0.5
6/12/1981	0.307	0.356	0.375	0.352	0.375	N/A	0.5
9/25/1985	0.276	0.365	0.375	0.284	0.375	N/A	0.5
5/19/1987	0.205	(Note 1)	0.375	0.215	0.375	N/A	0.5
2/4/1991	0.3251	0.4956 (Note 2)	0.375	0.3408	0.375	N/A	0.5
3/25/2004	0.1265	0.3351	0.5	0.2602	0.375	0.2602	0.5
4/11/2010	0.1775	0.21	0.5	0.1387	0.375	0.1387	0.5

Table 3.4.4-2 BSEP Unit 2 Type A Test History

Test Date	95% Upper Confidence Limit (wt.%/day)	As-Found Leakage (wt.%/day)	Acceptance Criteria (La) (wt.%/day)	As-Left Leakage (wt.%/day)	Acceptance Criteria (0.75La) (wt.%/day)	Performance Leakage Rate (wt.%/day)	Acceptance Criteria (La) (wt.%/day)
10/8/1974	0.153	0.153	0.375	0.153	0.375	N/A	0.5
7/14/1982	0.304	0.653 (Note 3)	0.375	0.318	0.375	N/A	0.5
9/24/1984	0.298	(Note 4)	0.375	0.293	0.375	N/A	0.5
5/5/1986	0.237	(Note 5)	0.375	0.24	0.375	N/A	0.5
2/19/1990	0.308	(Note 6)	0.375	0.334	0.375	N/A	0.5
12/2/1991	0.327	0.4956 (Note 7)	0.375	0.355	0.375	N/A	0.5
2/26/1993	0.318	0.442 (Note 8)	0.375	0.351	0.375	N/A	0.5
3/30/2005	0.3236	0.2922	0.5	0.2557	0.375	0.2602	0.5
4/1/2015	0.4237	0.4797	0.5	0.299	0.375	0.299	0.5

Tables 3.4.4.1 and 3.4.4.2 Notes:

Note 1: The BSEP Unit 1 1987 ILRT As-Found leakage rate exceeded its limit of 0.75 L_a (i.e., 0.375 wt.%/day) with a leakage rate greater than L_a. This was primarily due to immeasurable leakage on Penetration X9A, Feedwater Loop A Injection and Penetration X54E, Containment Monitor, CAC-AT-1262, Discharge. Penetration X9A was repaired during the 1987 refueling outage by repairing valve B21-F010B and repairing the leak-off line and packing on valve B21-F032A. Penetration X54E was repaired by replacing the discs in valves CAC-SV-1211E and CAC-SV-3439. Without the leakage additions from Penetrations X9A and X54A, the as-found leakage savings would have been approximately 0.049 wt.%/day.

Note 2: The BSEP Unit 1 1991 As-Found Leakage rate exceeded its limit of 0.75L_a (i.e., 0.375 wt.%/day) with a leakage rate 0.4956 wt.%/day. This was primarily due to excessive leakage on Penetration X9B, Feedwater Loop B Injection, Penetration X14, Reactor Water Clean Up Suction Line and Penetration X10, Reactor Core Isolation Cooling Turbine Steam Supply Line. Penetration X9B was repaired by replacing the soft seat ring on valve B21-F010B. Penetration X14 was repaired by replacing valves G31-F001 and G31-F004. Penetration X10 was repaired by replacing valves E51-F007 and E51-F008.

Note 3: During the 1982 Unit 2 ILRT, excessive leakage was noted in several areas of the containment structure following initial pressurization. One of the areas found to be contributing to the leakage was a root valve on a pressure instrument which was incorrectly left open. The valve was subsequently closed. Another area found to be contributing to the high leakage readings was a leak on a tubing connector to pressure recorder CAC-PT-2685 which was repaired. A third area contributing to the leakage was the RHR A Loop heat exchanger relief valve, E11-F055A. The leakage was secured by installing a gagging bolt and subsequent snooping of the relief valve confirmed no other leaks in the area. Also, during the data gathering phase, personnel performing leak searches found a number of small leaks throughout the plant, contributing to the excessive leakage, though no single large leaks were found. Leakages in the stem and packing of the temporary piping valves used for the pressurization were found and repaired. Caps were installed on lines which had no leakage but were discovered to be missing caps. Following the repairs of the items above, components were found to be mispositioned which were also leading to the excessive measured leakage. HPCI valves E41-F075 and E41-F079 along with RCIC valves E51-F066 and F51-F062 were positioned open rather than the required test position of closed. The other mispositioning event involved a sample line which was in service during the ILRT. These valves were subsequently correctly positioned.

Note 4: Local leakage rate testing of Unit 2 primary CIVs revealed a nonquantifiable leakage rate on several containment penetrations. These observed conditions made the calculation of the "As-Found" containment leakage indeterminate. The components contributing to the excessive leakage were B21-F010A and B21-F010B which were repaired by machining the disc and replacing the soft seat; B21-F032B, E51-F013 and G31-F039 which were repaired by removing G31-F039 from the flow path and installing a freeze seal to isolate the line; CAC-V47 which was repaired by resetting the actuator; CAC-X20A, CAC-V16 which were repaired by replacing V16; CAC-SV1263-4 and CAC-SV4409-3 which were removed from the system via design change;

CAC-PV1218C which was repaired by replacing the component and the valve internals; E11-F008, E11-F009 which was repaired by lapping the seats of E11-F009; E11-F001B which were repaired by performing maintenance on the test boundary valves; E11-F020A which was repaired by resetting torque switch, adjusting the Belville springs and resetting the torque switch; E11-F020B which was repaired by replacing the stem, resetting the torque switch, and lapping the seats; E21-F001A which was repaired by machining the disc and lapping the seat; E41-F021, E41-F049 which were repaired by lubricating the packing; E51-F001, E51-F040 which were repaired by lapping the seats and lubricating the valve stem; G31-F001, G31-F004 which were repaired by flushing the seats of the valve, lapping the seats, repacking the valve and retorquing the bonnet bolts; G31-F042 which was repaired by replacing the valve; RXS-PV1222B, PV1222C which were repaired by replacing the internals on both valves; and TD-V22, TD-V1 which were repaired by replacing all gaskets.

Note 5: During the 1986 Unit 2 ILRT, the total leakage savings due to performing Type B and C tests prior to the Type A test indicated that the acceptance criteria would have been exceeded due to two penetrations that could not be pressurized. The two penetrations which were unable to be pressurized were Penetration 13B (i.e., valves E11-F015B and E11-F017B) and Penetration 77C (i.e., valve RXS-SV-1222C). Both penetrations were repaired and retested with an As-Left leakage rate of 0 scfh.

Note 6: During the Unit 2 1990 ILRT, the total leakage savings due to performing Type B and C tests prior to the Type A test indicated that a leakage savings of 0.153 wt.%/day would have exceeded the acceptance criteria of L_a.

Note 7: The BSEP Unit 2 1991 As-Found Leakage rate exceeded its limit of 0.75 L_a (i.e., 0.375 wt.%/day) with a leakage rate 0.4956 wt.%/day. This was primarily due to excessive leakage on Penetration X220, Torus Purge to Standby Gas and Penetration X8, Main Steam Line Drain. Penetration X220 was repaired by repairing valves CAC-V7 and CAC-V8. Penetration X8 was repaired by rebuilding valve B21-F016 to restore the low spots found on the inboard disc seat and by lapping the seats and rebuilding valve B21-F019.

Note 8: The BSEP Unit 2 1992 As-Found Leakage rate exceeded its limit of 0.75 L_a (i.e., 0.375 wt.%/day) with a leakage rate 0.442 wt.%/day. This was primarily due to excessive leakage on Penetration X14, Reactor Water Clean Up Suction and Penetration X12, RHR Cooling Suction. Penetration X14 was repaired by rebuilding Valve G31-F001 to close the sealing gap and repair casting flaws found in the upper and lower wedges. Penetration X12 was repaired by rebuilding valve E11-F009 to restore low spots on the in-body seats.

As demonstrated in the Tables, BSEP Units 1 and 2 were required to accelerate the testing frequency of the ILRTs due to the As-Found failures which exceeded the 0.75 L_a leakage limit. The primary reason for the As-Found was the leakage savings additions from Type B and C testing of valves and penetrations, where leakage rates of repaired or replaced components from Type B and C testing are added into the ILRT results.

At the time of the As-Found ILRT failures, plant TS required ILRTs to be performed at each plant shutdown for refueling or every 18 months, whichever occurred first, until two consecutive ILRTs meet the specified leakage limit if two consecutive ILRTs failed to meet the 0.75 L_a leakage limit. On October 19, 1993, BSEP filed for an amendment to the TS to allow a one-time

exemption from the accelerated testing requirement to return the units to a normal ILRT frequency (i.e., Reference 26). On January 11, 1994, the NRC approved the one-time exemption from the accelerated containment ILRT requirements to return the containment ILRT frequency for both units to a normal test interval (i.e., Reference 27). The basis for the approval was the adequate assurance that there would not be any significant degradation in the primary containment leakage during the next Type A test interval since the primary contributors to the excessive leakage would be measured during the required LLRT Type B and Type C tests.

Performance Leakage Rate Determination

NEI 94-01 defines the performance leakage rate, or performance criteria, for the Type A ILRT as allowable leakage less than 1.0 L_a. Extensions of the Type A ILRT are allowed based upon two consecutive, periodic Type A ILRTs where the performance leakage rate is less than 1.0 L_a. The past two ILRTs for BSEP Unit 1 (i.e., 2004 and 2010) and Unit 2 (i.e., 2005 and 2015) had measured performance leakage rates less than 1.0 L_a (i.e., 0.5 wt.%/day). Since all tests were satisfactory, the BSEP ILRTs remained on an extended frequency. The current ILRT frequency for BSEP is 10 years. Tables 3.4.4-3 and 3.4.4-4 provide a breakdown of the calculation of the performance leakage rate for the past two ILRTs at BSEP Units 1 and 2.

Table 3.4.4-3 - Verification of Current Extended ILRT Interval for BSEP Unit 1						
Test Date	Measured Leakage Rate at 95% UCL (%wt./day)	Water Level Corrections (%wt./day)	Corrections for valves not in Accident Positions during Test (%wt./day)	Components Isolated During ILRT Due to Excessive Leakage (%wt./day)	Performance Leakage Rate (%wt./day) (Acceptance Criteria ≤ 0.5 wt.%/day	Test Method
3/25/2004	0.1265	0.0306	0.1031	0	0.2602	Total Time
4/11/2010	0.1775	-0.0862	0.0474	0	0.1387	Total Time

Table 3.4.4-4 - Verification of Current Extended ILRT Interval for BSEP Unit 2						
Test Date	Measured Leakage Rate at 95% UCL (%wt./day)	Water Level Corrections (%wt./day)	Corrections for valves not in Accident Positions during Test (%wt./day)	Components Isolated During ILRT Due to Excessive Leakage (%wt./day)	Performance Leakage Rate (%wt./day) (Acceptance Criteria ≤ 0.5 wt.%/day	Test Method
3/30/2005	0.1265	0.0306	0.1031	0	0.2602	Total Time
4/1/2015	0.2799	-0.0798	0.0989	0	0.299	Mass Point

3.5 Plant Specific Confirmatory Analysis

3.5.1 Methodology

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

1. NEI 94-01, Revision 3-A (i.e., Reference 2), the methodology used in EPRI TR-104285 (i.e., Reference 11).
2. The NEI document Interim Guidance for Performing Risk Impact Assessments in Support of One-Time Extensions for Containment Integrated Leakage Rate Test Surveillance Intervals (i.e., Reference 28).
3. The NRC regulatory guidance on the use of Probabilistic Risk Assessment (PRA) as stated in RG 1.200 (i.e., Reference 29) as applied to ILRT interval extensions.
4. Risk insights in support of a request for a change of the plant's licensing basis as outlined in RG 1.174 (i.e., Reference 7)
5. The methodology used for Calvert Cliffs to estimate the likelihood and risk implications of corrosion-induced leakage of steel liners going undetected during extended test interval (i.e., Reference 30).
6. The methodology used in EPRI 1009325, Revision 2-A (i.e., Reference 8).

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

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

The NRC report on performance-based leak testing, NUREG-1493, analyzed the effects of containment leakage on the health and safety of the public and the benefits realized from the containment leak rate testing. In that analysis, it was determined for a representative BWR plant (i.e., Peach Bottom), that increasing the containment leak rate from a nominal 0.5% per day to 5% per day leads to a barely perceptible increase in total population exposure and increasing the leak rate to 50% per day increases the total population exposure by less than 1%. Because ILRTs represent substantial resource expenditures, it is desirable to show that

extending the ILRT interval will not lead to a substantial increase in risk from containment isolation failures to support a reduction in the test frequency for BSEP.

NEI 94-01, Revision 3-A (i.e., Reference 2) supports using EPRI Report No. 1009325, Revision 2-A, "Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals" (i.e., Reference 8) for performing risk impact assessments in support of ILRT extensions. The Guidance provided in Appendix H of EPRI Report No. 1009325, Revision 2-A builds on the EPRI Risk Assessment methodology, EPRI TR-104285. This methodology is followed to determine the appropriate risk information for use in evaluating the impact of the proposed ILRT changes.

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

In the SER issued by the NRC letter dated June 25, 2008 (i.e., Reference 12), the NRC concluded that the methodology in EPRI TR-1009325, Revision 2, was acceptable for referencing by licensees proposing to amend their TS to extend the ILRT surveillance interval to 15 years, subject to the limitations and conditions noted in Section 4.0 of the Safety Evaluation (SE). Table 3.5.1-1 addresses each of the four limitations and conditions for the use of EPRI 1009325, Revision 2.

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

Limitation/Condition **(From Section 4.2 of SE)**	**BSEP 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.	BSEP PRA technical adequacy is addressed in Section 3.5.2 of this LAR and Attachment 6, "Brunswick Nuclear Plant: Evaluation of Risk Significance of Permanent ILRT Extension," Appendix A, PRA Model Technical Adequacy.

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

Limitation/Condition (From Section 4.2 of SE)	BSEP Response
2.a The licensee submits documentation indicating that the estimated risk increase associated with permanently extending the ILRT surveillance interval to 15 years is small, and consistent with the clarification provided in Section 3.2.4.5 of this SE.	RG 1.174 provides guidance for determining the risk impact of plant-specific changes to the licensing basis. RG 1.174 defines very small changes in risk as resulting in increases of CDF less than 1.0E-6/year. Since BSEP relies on containment accident pressure for ECCS NPSH during certain design basis accidents, extending the ILRT interval may impact CDF. The BSEP PRA model was used to estimate the potential change in CDF if containment accident pressure was unavailable due to a pre-existing containment leak. The containment accident pressure analysis performed in Section 5.2.7 of Attachment 6 of this submittal estimates the potential increase in the overall CDF to be 1.61E-08 for Unit 1 and 1.54E-08 for Unit 2, which are "very small" using the acceptance guidelines of RG 1.174. (i.e., Reference Attachment 6)
2.b Specifically, a small increase in population dose should be defined as an increase in population dose of less than or equal to either 1.0 person-rem per year or 1% of the total population dose, whichever is less restrictive.	The effect resulting from changing the Type A test frequency to 1-per-15 years, measured as an increase to the total integrated plant risk for those accident sequences influenced by Type A testing, is 4.98E-03 person-rem/year for Unit 1 and 4.67E-03 person-rem/year for Unit 2. NEI 94-01 states that a small population dose is defined as an increase of ≤ 1.0 person-rem/year, or ≤ 1% of the total population dose, whichever is less restrictive for the risk impact assessment of the extended ILRT intervals. The results of this calculation meet these criteria. Moreover, the risk impact for the ILRT extension when compared to other severe accident risks is negligible.

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

Limitation/Condition (From Section 4.2 of SE)		BSEP Response
2.c	In addition, a small increase in CCFP should be defined as a value marginally greater than that accepted in a previous one-time 15-year ILRT extension requests. This would require that the increase in CCFP be less than or equal to 1.5 percentage point.	The increase in the conditional containment failure probability from a 3-in-10 years interval to a 1 in 15 years interval is 1.20% for Unit 1 and 1.213% for Unit 2. NEI 94-01 states that increases in Conditional Containment Failure Probability (CCFP) of ≤ 1.5 is small. Therefore, this increase is judged to be small.
3.	The methodology in EPRI Report No. 1009325, Revision 2, is acceptable except for the calculation of the increase in expected population dose (per year of reactor operation). In order to make the methodology acceptable, the average leak rate accident case (accident case 3b) used by the licensees shall be 100 L_a instead of 35 L_a.	The representative containment leakage for Class 3b sequences is 100 L_a based on the guidance provided in EPRI Report No. 1009325, Revision 2. It should be noted that this is more conservative than the earlier previous industry Type A test interval extension requests, which utilized 35 L_a for the Class 3B sequences.
4.	A license amendment request (LAR) is required in instances where containment over-pressure is relied upon for ECCS performance.	Section 3.3 of this enclosure summarizes the current licensing basis for application of CAP at BSEP.

3.5.2 PRA Acceptability

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

The BSEP internal events PRA model (i.e., MOR16) is used to calculate CDF and large early release frequency (LERF) for the permanent 15-year ILRT extension. Any elements of the supporting requirements detailed in ASME/ANS RA-Sa-2009 (i.e., Reference 31) that could be significantly affected by the application are required to meet Capability Category (CC) II requirements.

The BSEP Units 1 and 2 Internal Events and Internal Flooding PRA Peer Review was performed in April 2010 using the NEI 05-04 process (i.e., Reference 32), the ASME PRA Standard (i.e., Reference 31) and RG 1.200, Revision 2 (i.e., Reference 29). The purpose of this review was to establish the acceptability of the PRA for the spectrum of potential risk-informed plant licensing applications for which the PRA may be used. The 2010 BSEP PRA Peer Review was a full-scope review of the Technical Elements of the Internal Events and Internal Flooding, at-power PRA. A focused scope peer review of the Internal Flood model was conducted in December 2016, which covered 28 SRs.

The ASME PRA Standard has 325 individual Supporting Requirements (SRs); 322 SR are applicable to the BSEP PRA. Three of the ASME/ANS PRA Standard Supporting Requirements are not applicable to BSEP (e.g., PWR-related, linked event tree methodology-related). Of the 322 ASME/ANS PRA Standard Supporting Requirements applicable to BSEP, approximately 88% are supportive of Capability Category II or greater. Of the 79 unique Facts and Observations (F&Os) generated by the Peer Review Team, 44 were considered peer review Findings and 35 were Suggestions.

An F&O closure technical review was conducted in August 2017 and most, but not all, open F&Os were reviewed for closure. Following the F&O closure, 15 Internal Event and Internal Flooding F&Os remain open; these F&Os are dispositioned in Section A.1.1 of Attachment 6 of this submittal for their impact on the ILRT extension. All of the Finding Level F&Os have been determined to not significantly affect the ILRT extension analysis.

3.5.2.2 Fire PRA Quality Statement for Permanent 15-Year ILRT Extension

The BSEP Fire Probabilistic Risk Assessment (FPRA) Peer Review was performed December 2011 using the NEI 07-12 process (i.e., Reference 33), the ASME PRA Standard (i.e., Reference 31), and RG 1.200, Revision 2 (i.e., Reference 29). The purpose of this review was to establish the acceptability of the FPRA for the spectrum of potential risk-informed plant licensing applications for which the FPRA may be used. The 2011 BSEP FPRA Peer Review was a full-scope review of all of the technical elements of the BSEP at-power 2011 MOR Fire PRA against all technical elements in Section 4 of the ASME/ANS Combined PRA Standard, including the referenced internal events SRs in Section 2 of the ASME/ANS Combined PRA Standard (i.e., Reference 31).

The Peer Review team consisted of six team members, with extensive qualifications in all areas of FPRA as required by NEI 07-12 (i.e., Reference 33). The team members experience averaged over 20 years in PRA or Fire Protection, with extensive experience in FPRA, the FPRA Section of the Standard, and NUREG/CR-6850.

The Fire PRA Section of the ASME PRA Standard has 182 individual SRs, and references 237 individual SRs in the internal events PRA section of the Standard; the BSEP Peer Review included all of the SRs and all applicable reference SRs (i.e., see Table A.2-1 of Attachment 6 of this submittal). For the assessment of the reviewed ASME PRA Standard SRs, 105 unique F&Os were generated by the Peer Review team, 53 were peer review Findings, 50 were Suggestions, and one was an "Unreviewed Analytical Method."

An F&O Finding closure technical review was conducted in July 2017 to review all open Fire PRA F&Os. Following the F&O closure, six F&Os remain open; these F&Os are dispositioned in Section A.2.1of Attachment 6 of this submittal for their impact on the ILRT extension. All the Finding Level F&Os have been determined to not significantly affect the ILRT extension analysis.

3.5.2.3 High Winds PRA Quality Statement for Permanent 15-Year ILRT Extension

The BSEP Units 1 and 2 High Winds PRA Peer Review was performed January 2012 using the ASME PRA Standard (i.e., Reference 31) and RG 1.200, Rev. 2 (i.e., Reference 29). The purpose of this review was to establish the acceptability of the High Winds PRA for the spectrum of potential risk-informed plant licensing applications for which the High Winds PRA may be used. The 2012 BSEP High Winds PRA Peer Review was a full-scope review of all of

the technical elements of the BSEP at-power 2011 MOR High Winds PRA against all technical elements of the PRA (i.e., Reference 34).

The ASME PRA Standard has 29 individual SRs pertaining to High Winds; the BSEP Peer Review included all of the SRs.

An F&O Finding closure technical review of the High Winds PRA and a focused-scope closure review of the High Winds HRA were conducted in July 2017, with the documentation finalized in August 2017, to review all open High Winds PRA F&Os. Following the F&O closure all High Winds PRA F&Os are closed.

3.5.3 Summary of Plant-Specific Risk Assessment Results

Based on the results from Section 5.2 and the sensitivity calculations in Section 5.3 of Attachment 6 of this submittal, the following conclusions regarding the assessment of the plant risk are associated with extending the Type A ILRT test frequency to fifteen years:

- RG 1.174 (i.e., Reference 7) provides guidance for determining the risk impact of plant-specific changes to the licensing basis. RG 1.174 defines very small changes in risk as resulting in increases of CDF less than 1.0E-06/year. Since BSEP relies on containment accident pressure for ECCS NPSH during certain design basis accidents, extending the ILRT interval may impact CDF. The BSEP PRA model was used to estimate the potential change in CDF if containment accident pressure was unavailable due to a pre-existing containment leak. The containment accident pressure analysis performed in Section 5.2.7 of Attachment 6 estimates the potential increase in the overall CDF to be 1.61E-08 for Unit 1 and 1.54E-08 for Unit 2, which are "very small" using the acceptance guidelines of RG 1.174.

- When external event risk is included, the increase in CDF resulting from a change in the Type A ILRT test interval from 3 in 10 years to 1 in 15 years is estimated as 1.10E-07/year for Units 1 and 2 using the EPRI guidance. As such, the estimated change in CDF is determined to be "very small" using the acceptance guidelines of RG 1.174 (i.e., Reference 7). The risk change resulting from a change in the Type A ILRT test interval from 3-in-10 years to 1-in-15 years bounds the 1 in 10 years to 1 in 15 years risk change.

- RG 1.174 (i.e., Reference 7) 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 increases in LERF less than 1.0E-07/year. The increase in LERF resulting from a change in the Type A ILRT test interval from 3-in-10 years to 1-in-15 years is estimated as 6.03E-08/year for Unit 1 and 5.67E-08/year for Unit 2 using the EPRI guidance; this value increases negligibly if the risk impact of corrosion-induced leakage of the steel liners occurring and going undetected during the extended test interval is included. As such, the estimated change in LERF is determined to be "very small" using the acceptance guidelines of RG 1.174.

- When external event risk is included, the increase in LERF resulting from a change in the Type A ILRT test interval from 3-in-10 years to 1-in-15 years is estimated as 4.05E-07/year for Unit 1 and 4.33E-07/year for Unit 2 using the EPRI guidance, and total LERF is 5.55E-06/year for Unit 1 and 5.53E-06/year for Unit 2. As such, the estimated change in LERF is determined to be "small" using the acceptance guidelines of RG 1.174 (i.e., Reference 7).

The risk change resulting from a change in the Type A ILRT test interval from 3-in-10 years to 1-in-15 years bounds the 1-in-10 years to 1-in-15 years risk change.

- The effect resulting from changing the Type A test frequency to 1-in-15 years, measured as an increase to the total integrated plant risk for those accident sequences influenced by Type A testing, is 4.98E-03 person-rem/year for Unit 1 and 4.67E-03 person-rem/year for Unit 2. NEI 94-01 (i.e., Reference 2) states that a small population dose is defined as an increase of ≤ 1.0 person-rem per year, or ≤ 1% of the total population dose, whichever is less restrictive for the risk impact assessment of the extended ILRT intervals. The results of this calculation meet these criteria. Moreover, the risk impact for the ILRT extension when compared to other severe accident risks is negligible.
- The increase in the conditional containment failure probability from the 3-in-10 years interval to 1-in-15 years interval is 1.206% for Unit 1 and 1.213% for Unit 2. NEI 94-01 (i.e., Reference 2) states that increases in CCFP of ≤ 1.5% is small. Therefore, this increase is judged to be small.

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

Previous Assessments

In NUREG-1493 (Reference 10), the NRC has previously concluded that:

- Reducing the frequency of Type A tests from 3-in-10 years to 1-in-20 years was found to lead to an imperceptible increase in risk. The estimated increase in risk is very small because ILRTs identify only a few potential containment leakage paths that cannot be identified by Type B or Type C testing, and the leaks that have been found by Type A tests have been only marginally above existing requirements.
- Given the insensitivity of risk to containment leakage rate and the small fraction of leakage paths detected solely by Type A testing, increasing the interval between integrated leakage-rate tests is possible with minimal impact on public risk. The impact of relaxing the ILRT frequency beyond 1-in-20 years has not been evaluated. Beyond testing the performance of containment penetrations, ILRTs also test integrity of the containment structure.

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

3.5.4 RG 1.174 Revision 3 Defense in Depth Evaluation

RG 1.174, Revision 3 (i.e., Reference 35) describes an approach that is acceptable for developing risk-informed applications for a licensing basis change that considers engineering and applies risk insights. One of the considerations included in RG 1.174 is Defense in Depth. Defense in Depth is a safety philosophy that employs successive compensatory measures to provide accidents or mitigate damage if a malfunction, accident, or naturally caused event occurs at a nuclear facility. The following seven considerations as presented in RG 1.174 Revision 3, Section 2.1.1.2 will serve to evaluate the proposed licensing basis change for overall impact on Defense in Depth.

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

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

Response:

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

As shown in NUREG-1493, Performance-Based Containment Leak-Test Program (i.e., Reference 10), increasing the test frequency of ILRTs up to a 20-year test interval was found to lead to an imperceptible increase in risk. The estimated increase in risk is very small because ILRTs identify only a few potential containment leakage paths that cannot be identified by Type B or Type C testing. The study also concluded that extending the frequency of Type B tests is possible with no adverse impact on risk as identified leakage through Type B mechanical penetrations are both infrequent and small. Finally, the study concluded that Type B and C tests could identify the vast majority (i.e., greater than 95 percent) of all potential leakage paths.

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

PRA Response:

The usage of the risk metrics of LERF, population dose, and CCFP collectively ensures the balance between prevention of core damage, prevention of containment failure, and consequence mitigation is preserved. The change in LERF is "small" per RG 1.174, and the change in population dose and CCFP are "small" as defined in this analysis and consistent with the NRC SER on NEI 94-01 Revision 2-A.

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

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

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

Response:

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

PRA Response:

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

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

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

System redundancy, independence, and diversity result in high availability and reliability of the function and also help ensure that system functions are not reliant on any single feature of the design. Redundancy provides for duplicate equipment that enables the failure or unavailability of at least one set of equipment to be tolerated without loss of function. Independence of equipment implies that the redundant equipment is separate such that it does not rely on the same supports to function. This independence can sometimes be achieved by the use of physical separation or physical protection. Diversity is accomplished by having equipment that performs the same function rely on different attributes such as different principles of operation, different physical variables, different conditions of operation, or production by different manufacturers which helps reduce common-cause failure (CCF). A proposed change might reduce the redundancy, independence, or diversity of systems. The intent of this consideration is to ensure that the ability to provide the system function is commensurate with the risk of scenarios that could be mitigated by that function. The consideration of uncertainty, including the uncertainty inherent in the PRA, implies that the use of redundancy, independence, or diversity provides high reliability and availability and also results in the ability to tolerate failures or unanticipated events.

Response:

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

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

availability of the containment structure to perform its safety function in the event of unanticipated events.

PRA Response:

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

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

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

Response:

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

PRA Response:

Adequate defense against CCFs is preserved. The Type A test detects problems in the containment, which may or may not be the result of a CCF; such a CCF may affect failure of

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

5. Maintain multiple fission product barriers.

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

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

Response:

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

PRA Response:

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

6. Preserve sufficient defense against human errors.

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

Response:

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

PRA Response:

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

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

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

Response:

The purpose of the proposed change is to extend the testing frequencies of the Type A ILRT from 10 years to 15 years and select Type C LLRTs from 60-months to 75-months. The proposed extensions do not involve either a physical change to the plant or a change in the manner in which the plant is operated or controlled. As part of the proposed change, BSEP will be required to adopt the performance-based testing standards outlined in NEI 94-01, Revisions 2-A and 3-A along with ANSI/ANS 56.8-2002. The leakage limits imposed by plant TS remain unchanged when adopting the performance-based testing standards outlined in NEI 94-01 Revision 3-A and ANSI/ANS 56.8-2002. Plant design limits imposed by the Updated Final

Safety Analysis Report (UFSAR) also remain unchanged as a result of the proposed change. Therefore, the proposed change continues to meet the intent of the plant's design criteria to ensure the integrity of the BSEP containment pressure boundary.

PRA Response:

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

Conclusion:

The responses to the seven Defense in Depth questions above conclude that the existing Defense in Depth has not been diminished, rather, in some instances has been increased. Therefore, the proposed change does not comprise a reduction in safety.

3.6 Non-Risk Based Assessment

3.6.1 Nuclear Coatings Program

The Nuclear Coatings Program provides a standardized method of selecting, procuring, applying, maintaining, and periodically assessing coatings so they can be used to minimize the adverse impacts of degraded (i.e., detached) coatings on systems, structures, and components (SSCs), minimize material degradation of SSCs, facilitate decontamination of SSCs, and satisfy licensing and regulatory commitments.

Service Level I coatings are applied to exposed surfaces inside the reactor containment where coating failure (i.e., detachment) could adversely affect the operation of post-accident fluid systems and thereby, impair safe shutdown. Systems which could be impacted by detached coatings include the ECCS and the Containment Spray system. Therefore, coating systems used within the reactor containment are required to be Qualified Coating Systems.

Site Engineering personnel along with site QC staff are responsible for performing coatings assessments and inspections. Service Level I and Service Level III (i.e., Safety-Related) coating work at BSEP is considered to be Special Processes. Special Processes are controlled and accomplished by qualified personnel using qualified procedures in accordance with applicable codes, standards, specifications, criteria and other special requirements. The personnel are qualified in accordance with applicable employee training and qualification systems. The coating surveillance is performed on a 24-month basis. Additionally, coating degradations found during routine maintenance operations are tracked via the Nuclear Coatings Program for timely resolution.

3.6.1.1 Unqualified/Degraded Coatings in Containment

Site Engineering is responsible for verifying that the amount of unqualified coatings allowed in the primary containment does not exceed limits defined in calculations and the UFSAR. A calculation is performed on the ECCS to ensure the amount of unqualified coatings in containment does not degrade the ECCS system. Areas where coatings are considered degraded are documented and tracked by a Coatings Exempt Log to ensure that the quality of unqualified coatings in the torus do not exceed analyzed limits.

The total amount of protective coating debris or Unqualified Coatings inside the primary containment is limited to 6,667 cubic feet (ft^3) for each unit. The Maintenance Rule (a)(1) limit of

5.175 ft^3 has been set as an alert limit for each unit. This quantity was considered acceptable based on ECCS suction strainer design analysis.

The estimated volumes of Unqualified Coatings inside the Unit 1 and Unit 2 BSEP primary containments are summarized in Tables 3.6.1-1 and 3.6.1-2 below. The total volume for each containment is still well below the design limit and is considered to be a conservative estimate.

Table 3.6.1-1 Unit 1 Primary Containment Unqualified Coatings following B1R22 Refueling Outage, March 2016	
Design Limit	6.667 ft^3
Maintenance Rule (a)(1) Limit	5.175 ft^3
Total Volume following B121R1	3.120 ft^3
Percent of Maintenance Rule (a)(1) limit at start up	60.5%

Table 3.6.1-2 Unit 2 Primary Containment Unqualified Coatings following B223R1 Refueling Outage, March 2017	
Design Limit	6.667 ft^3
Maintenance Rule (a)(1) Limit	5.175 ft^3
Total Volume following B121R1	3.647 ft^3
Percent of Maintenance Rule (a)(1) limit at start up	70.5%

3.6.2 Maintenance Rule Structural Monitoring Program

The Structural Monitoring Program was established to ensure BSEP Maintenance Rule structural components are monitored and evaluated in accordance with the requirements of 10 CFR 50.65 using the guidance of NEI 96-03. The Maintenance Rule requires that licensees monitor the performance or condition of structures, systems, or components, against established criteria. Performance monitoring of structures is impracticable; thus, condition monitoring has been set forth as the method of determining compliance with these established requirements.

Baseline inspections were performed for the structural systems. The findings from these inspections provided input for determining the appropriate inspection frequency based on current condition and safety significance. The inspection frequencies were determined and justification documented in the Maintenance Rule database for an appropriate periodic inspection interval. Preventative Maintenance (PM) routes were created for both accessible and normally inaccessible areas.

The structural systems inspections will continue to be performed as established. The structural system engineer continues to inspect structures from normally available access locations utilizing lighting and binoculars for areas not readily accessible. The structural system inspection coincides with the non-structural system inspection allowing immediate interaction between the discipline system engineer and the structural system engineer when asked to provide assistance with evaluating structural deficiencies.

Boundaries are established between structural systems and structural components associated with non-structural systems to ensure that inspections are complete and thorough. The structural system engineer is responsible for inspecting structural systems. The discipline system engineer is responsible for inspecting structural components associated with their systems. System boundaries define where the structural system engineer and discipline engineer stop their inspection.

3.6.3 Containment Inservice Inspection Program

The BSEP Containment Inspection Program is currently beginning its third inspection interval. The governing code of record for the second inspection interval was the 2001 Edition with the 2003 Addenda of the ASME Code, Section XI; hereafter referred to as the ASME Code, Section XI. The third inspection interval for BSEP became effective on May 11, 2018 and will end on May 10, 2028, and will use the 2007 Edition with the 2008 Addenda of the ASME Code, Section XI. The Containment plan is being merged into the overall ISI plan which is in its 5th Interval beginning May of 2018 and ending May of 2028. Going forward for consistency, the Containment plan will be referenced as being in the Fifth Inspection interval.

<table>
<tr><th colspan="3">Table 3.6.3-1 BSEP Unit 1 Third Containment MC/CC Inspection Interval[4]</th></tr>
<tr><td>First Period[2,3]</td><td>Second Period[2,3]</td><td>Third Period[2]</td></tr>
<tr><td>5/11/2018 - 5/10/2022</td><td>5/11/2022 - 5/10/2025</td><td>5/11/2025 - 5/10/2028[1]</td></tr>
<tr><td>Outage 1 (B1R23)</td><td rowspan="2">Outage 3 (B1R25)</td><td>Outage 4 (B1R26)</td></tr>
<tr><td>Outage 2 (B1R24)</td><td>Outage 4 (B1R27)</td></tr>
</table>

<table>
<tr><th colspan="3">Table 3.6.3-2 BSEP Unit 2 Third Containment MC/CC Inspection Interval[4]</th></tr>
<tr><td>First Period[2,3]</td><td>Second Period[2,3]</td><td>Third Period[2,3]</td></tr>
<tr><td>5/11/2018 - 5/10/2021</td><td>5/11/2021 - 5/10/2024</td><td>5/11/2024 - 5/10/2028[1]</td></tr>
<tr><td>Outage 1 (B2R24)</td><td rowspan="2">Outage 3 (B2R26)</td><td>Outage 4 (B2R27)</td></tr>
<tr><td>Outage 2 (B2R25)</td><td>Outage 4 (B2R28)</td></tr>
</table>

Notes:

1. Unit 1 Fifth Interval end date for Class MC and CC components may be extended to no later than May 10, 2029 and may be reduced to no earlier than May 10, 2027. These provisions do not apply to inspection interval end dates for Class 1, 2, and 3 components.

2. Inspection periods for Subsection IWL (Class CC components) shall comply with the requirements of IWL-2410, based on a rolling 5-year frequency (+/- 1 year) from the completion date of the Structural Integrity Test (SIT). During the 5th Interval, IWL Examinations shall be performed only during the following periods:

    a. Unit 1:

        - IWL Period 1: August 20, 2020 through August 20, 2022 (i.e., includes Refueling Outage B1R24)

        - IWL Period 2: August 20, 2025 through August 20, 2027 (i.e., includes Refueling Outage B1R26)

    b. Unit 2:

        - IWL Period 1: October 8, 2018 through October 8, 2020 (i.e., includes Refueling Outage B2R24)

        - IWL Period 2: October 8, 2023 through October 8, 2025 (i.e., includes Refueling Outage B2R27)

3. The duration of the inspection periods has been adjusted, as permitted by IWA-2430(c)(3), to allow for Period 1 to have two (2) refueling outages, Period 2 to have a single (1) refueling outage, and Period 3 to have two (2) refueling outages.

4. The subsequent (i.e., 3rd) BSEP Inservice Inspection Interval Program for Class MC and CC components started on May 11, 2018, along with the start of the 5th Inservice Inspection Interval Program for Class 1, 2 and 3 components. To avoid confusion with regard to which inspection interval is being implemented, BSEP shall hereafter refer to the inspection interval starting on May 11, 2018 as the Fifth Inservice Inspection Interval for Class 1, 2, 3, MC and CC components.

<u>Code of Federal Regulations 10 CFR 50.55a Conditions</u>

The following mandatory and optional Code of Federal Regulations Conditions are included in 10 CFR 50.55a (i.e., dated July 17, 2017). These conditions were reviewed for inclusion in the ISI Plan and include only those 10 CFR 50.55a conditions applicable to the Inservice Inspection Plan developed using the 2007 Edition with the 2008 Addenda of Section XI are listed below:

- 50.55a(b)(2)(vi) *Section XI condition: Effective edition and addenda of Subsection IWE and Subsection IWL*. Licensees that implemented the expedited examination of containment, in accordance with Subsection IWE and Subsection IWL, during the period from September 9, 1996, to September 9, 2001, may use either the 1992 Edition with the 1992 Addenda or the 1995 Edition with the 1996 Addenda of Subsection IWE and Subsection IWL, as conditioned by the requirements in paragraphs (b)(2)(viii) and (ix) of

this section, when implementing the initial 120-month inspection interval for the containment inservice inspection requirements of this section. Successive 120-month interval updates must be implemented in accordance with paragraph (g)(4)(ii) of this section.

During the 5th Inservice Inspection Interval, BSEP is updating the applicable Section XI Code of Record in accordance with paragraph (g)(4)(ii).

- 50.55a(b)(2)(viii) *Section XI condition: Concrete containment examinations*. Applicants or licensees applying Subsection IWL, 1992 Edition with the 1992 Addenda, must apply paragraphs (b)(2)(viii)(A) through (E) of this section. Applicants or licensees applying Subsection IWL, 1995 Edition with the 1996 Addenda, must apply paragraphs (b)(2)(viii)(A), (b)(2)(viii)(D)(*3*), and (b)(2)(viii)(E) of this section. Applicants or licensees applying Subsection IWL, 1998 Edition through the 2000 Addenda, must apply paragraphs (b)(2)(viii)(E) and (F) of this section. Applicants or licensees applying Subsection IWL, 2001 Edition through the 2004 Edition, up to and including the 2006 Addenda, must apply paragraphs (b)(2)(viii)(E) through (G) of this section. Applicants or licensees applying Subsection IWL, 2007 Edition up to and including the 2008 Addenda must apply paragraph (b)(2)(viii)(E) of this section. Applicants or licensees applying Subsection IWL, 2007 Edition with the 2009 Addenda through the latest edition and addenda incorporated by reference in paragraph (a)(1)(ii) of this section, must apply paragraphs (b)(2)(viii)(H) and (I) of this section.

  During the 5th Inservice Inspection Interval, BSEP shall comply with the condition in§50.55a(b)(2)(viii)(E).

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

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

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

  (*3*) A description of necessary corrective actions.

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

Subsection IWE, 2007 Edition through the latest edition and addenda incorporated by reference in paragraph (a)(1)(ii) of this section, must satisfy the requirements of paragraphs (b)(2)(ix)(A)(*2*) and (b)(2)(ix)(B) and (J) of this section.

During the 5th Inservice Inspection Interval, BSEP shall comply with the condition in §50.55a(b)(2)(ix)(A)(2), §50.55a(b)(2)(ix)(B), and §50.55a(b)(2)(ix)(J).

- 50.55a(b)(2)(ix)(A) *Metal containment examinations: First provision*. For Class MC applications, the following apply to inaccessible areas.

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

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

  > (*i*) A description of the type and estimated extent of degradation, and the conditions that led to the degradation;
  >
  > (*ii*) An evaluation of each area, and the result of the evaluation; and
  >
  > (*iii*) A description of necessary corrective actions.

- 50.55a(b)(2)(ix)(B) *Metal containment examinations: Second provision*. When performing remotely the visual examinations required by Subsection IWE, the maximum direct examination distance specified in Table IWA–2210–1 (1992 Edition through 2004 Edition) or Table IWA–2211–1 (2005 Addenda through the latest edition and addenda incorporated by reference in paragraph (a)(1) of this section) may be extended and the minimum illumination requirements specified 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.

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

- 50.55a(g)(4)(v)(A) *Metal and concrete containments: First provision.* Metal containment pressure retaining components and their integral attachments must meet the inservice inspection, repair, and replacement requirements applicable to components that are classified as ASME Code Class MC;

This requirement imposes IWE on metal containments that were not designed in accordance with ASME Section III, Subsection NE.

- 50.55a(g)(4)(v)(B) *Metal and concrete containments: Second provision.* Metallic shell and penetration liners that are pressure retaining components and their integral attachments in concrete containments must meet the inservice inspection, repair, and replacement requirements applicable to components that are classified as ASME Code Class MC.

  This requirement imposes IWE on metallic shell and penetration liners of concrete containments.

- 50.55a(g)(4)(v)(C) *Metal and concrete containments: Third provision.* Concrete containment pressure retaining components and their integral attachments, and the post-tensioning systems of concrete containments, must meet the inservice inspections, repair, and replacement requirements applicable to components that are classified as ASME Code Class CC.

  This requirement imposes IWL on concrete containments that were not designed and constructed as Class CC components in accordance with ASME Section III, Division 2.

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

Table 3.6.2-3 BSEP Unit 1 E-A Examinations

Item Numbers	Parts Examined	Number of Items	Number of Examinations Scheduled by Period		
			1	2	3
E1.10 E1.11	Containment Vessel Pressure Retaining Boundary Accessible Surface Areas	203	203	203	203
E1.12	Wetted Surfaces of Submerged Areas	25	11	9	5
E1.20	BWR Vent System Accessible Surface Areas	19	0	0	19
E1.30	Moisture Barrier	1	1	1	1

Table 3.6.2-4 BSEP Unit 2 E-A Examinations

Item Numbers	Parts Examined	Number of Items	Number of Examinations Scheduled by Period		
			1	2	3
		203	203	203	203

Table 3.6.2-4 BSEP Unit 2 E-A Examinations					
Item Numbers	Parts Examined	Number of Items	Number of Examinations Scheduled by Period		
			1	2	3
E1.10 E1.11	Containment Vessel Pressure Retaining Boundary Accessible Surface Areas				
E1.12	Wetted Surfaces of Submerged Areas	25	11	9	5
E1.20	BWR Vent System Accessible Surface Areas	19	0	0	19
E1.30	Moisture Barrier	1	1	1	1

Notes:

1. Portions of the surfaces (including bolted connections) of electrical penetrations are considered inaccessible for general visual examination in accordance with Category E-A, E1.11 because welded electrical junction boxes are attached just off of the containment wall, not allowing sufficient space to perform this visual examination. Surfaces are considered to be accessible for visual examination if the examination can be performed, either directly or remotely, by line of sight from available viewing angles from floors, platforms, walkways, ladders, or other permanent vantage points, as specified in IWE-2310(c).

Table IWE-2500-01, Examination Category E-C, Containment Surfaces Requiring Augmented Examination

Table 3.6.2-5 BSEP Unit 1 E-C Examinations					
Item Numbers	Parts Examined	Number of Items	Number of Examinations Scheduled by Period		
			1	2	3
E4.10 E4.11	Containment Surface Areas - Visible Surfaces	0	0	0	0
E4.12	Surface Area Grid - Minimum Wall Thickness Location	0	0	0	0

Table 3.6.2-6 BSEP Unit 2 E-C Examinations					
Item Numbers	Parts Examined	Number of Items	Number of Examinations Scheduled by Period		
			1	2	3
E4.10 E4.11	Containment Surface Areas - Visible Surfaces	0	0	0	0
E4.12	Surface Area Grid - Minimum Wall Thickness Location	0	0	0	0

Notes:

1. At the start of the Fifth ISI Interval, there were no items identified requiring examination in accordance with Category E-C, Items E4.11 or E4.12. During the previous (Second) Containment ISI Interval, there were some Unit 2 items that required examination in accordance with Category E-C, but the requirements of IWE-2420(d) have been satisfied so these examinations are no longer required.

Table IWE-2500-1, Examination Category E-G, Pressure Retaining Bolting

Table 3.6.2-7 BSEP Unit 1 E-C Examinations

Item Numbers	Parts Examined	Number of Items	Number of Examinations Scheduled by Period		
			1	2	3
E8.10	Bolted Connections	16	4	5	7

Table 3.6.2-8 BSEP Unit 2 E-C Examinations

Item Numbers	Parts Examined	Number of Items	Number of Examinations Scheduled by Period		
			1	2	3
E8.10	Bolted Connections	16	5	11	0

Note: 100 percent of the examinations are required to be performed by the end of Interval. Deferral to the end of the interval is permissible. Examinations may be performed at any time during the interval and may be performed with the connection assembled and bolting in place under tension, provided the connection is not disassembled during the interval. If the bolted connection is disassembled for any reason during the interval, the examination shall be performed with the connection disassembled.

Subsection IWL for Class CC

Table 3.6.2-9 BSEP Unit 1 L-A Examinations

Item Numbers	Parts Examined	Areas Required to be Examined During Each Period
L1.10 L1.11	Concrete Surface All Accessible Surface Areas	100% (18 of 18 Areas)
L1.12	Suspect Areas	100% (If Any)

Table 3.6.2-10 BSEP Unit 2 L-A Examinations

Item Numbers	Parts Examined	Areas Required to be Examined During Each Period
L1.10 L1.11	Concrete Surface All Accessible Surface Areas	100% (18 of 18 Areas)

L1.12	Suspect Areas	100% (If Any)

Note: The IWL examination periods are as follows and do not align with those for Class 1, 2, 3 and MC Components:

a. Unit 1: IWL Period 1 – August 20, 2020 to August 20, 2022
IWL Period 2 – August 20, 2025 to August 20, 2027

b. Unit 2: IWL Period 1 – October 8, 2018 to October 8, 2020
IWL Period 2 – October 8, 2023 to October 8, 2025

3.6.4 Supplemental Inspection Requirements

With the implementation of the proposed change, TS 5.5.12 will be revised by replacing the reference to RG 1.163 (i.e., Reference 1) with reference to NEI 94-01, Revision 3-A (i.e., 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"

BSEP License Amendments 245 and 273 were approved on February 8, 2008, to allow the performance of the visual examinations of the containment pursuant to ASME Code Section XI, Subsections IWE and IWL, in lieu of the visual examinations performed pursuant to RG 1.163. The containment visual examination for the BSEP is implemented by the Primary Containment Inspection procedure. The purpose of this procedure is to perform examinations to assess the general condition of primary containment and to detect evidence of degradation that may affect structural integrity or leak tightness. This procedure fulfills the surveillance requirements of the Containment ISI Program Plan (i.e., IWE / IWL Plan), as all areas of the shell and liner which are accessible for direct or qualified remote examination are subject to these requirements. Supplemental inspections will not be required.

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

BSEP Types B and C testing program requires testing of electrical penetrations, airlocks, hatches, flanges, and CIVs in accordance with 10 CFR 50, Appendix J, Option B and RG 1.163 (i.e., Reference 1). The results of the test program are used to demonstrate that proper maintenance and repairs are made on these components throughout their service life. The Types B and C testing program provides a means to protect the health and safety of plant personnel and the public by maintaining leakage from these components below appropriate limits. In accordance with Unit 1 and Unit 2 TS 5.5.12, the allowable maximum pathway total Types B and C leakage is 0.6 L_a (159.78 standard cubic feet per hour (SCFH)) where L_a equals approximately 266.3 SCFH.

As discussed in NUREG-1493 (i.e., Reference 10), Type B and Type C tests can identify the vast majority of all potential containment leakage paths. Type B and Type C testing will continue to provide a high degree of assurance that containment integrity is maintained.

A review of the Type B and Type C test results from 2007 through 2018 for BSEP has shown substantial margin between the actual As-Found (AF) and As-Left (AL) outage summations and the regulatory requirements as described below:

- The As-Found minimum pathway leak rate average for BSEP Unit 1 shows an average of 36.42% of 0.6 L_a with a high of 78.02% 0.6 L_a.

- The As-Left maximum pathway leak rate average for BSEP Unit 1 shows an average of 59.60% of 0.6 L_a with a high of 78.04% 0.6 L_a.
- The As-Found minimum pathway leak rate average for BSEP Unit 2 shows an average of 31.17% of 0.6 L_a with a high of 40.12% 0.6 L_a.
- The As-Left maximum pathway leak rate average for BSEP Unit 2 shows an average of 61.80% of 0.6 L_a with a high of 87.14% 0.6 L_a.

Tables 3.6.5-1 and 3.6.5-2 provide LLRT data trend summaries for BSEP inclusive of the 2010 and 2015 ILRTs.

Table 3.6.5-1 BSEP Unit 1 Type B and C LLRT Combined As-Found / As-Left Trend Summary						
RFO / Year	2008	2010	2012	2014	2016	2018
	B117R1	B118R1	B119R1	B120R1	B121R1	B122R2
AF Min Path (SCFH)	54.397	64.885	124.662	40.734	35.013	29.474
Fraction of 0.6 L_a (percent)	34.04%	40.61%	78.02%	25.49%	21.91%	18.45%
AL Max Path (SCFH)	124.690	106.929	80.037	94.703	67.716	97.254
Fraction of 0.6 L_a (percent)	78.04%	66.92%	50.09%	59.27%	42.38%	60.87%
AL Min Path (SCFH)	53.337	35.485	26.760	35.921	25.007	27.525
Fraction of 0.6 L_a (percent)	33.38%	22.21%	16.75%	22.48%	15.65%	17.23%

Table 3.6.5-2 BSEP Unit 2 Type B and C LLRT Combined As-Found / As-Left Trend Summary						
RFO / Year	2007	2009	2011	2013	2015	2017
	B218R1	B219R1	B220R1	B221R1	B222R1	B223R1
AF Min Path (SCFH)	64.108	36.255	51.365	56.465	54.659	35.986
Fraction of 0.6 L_a (percent)	40.12%	22.69%	32.15%	35.34%	34.21%	22.52%
AL Max Path (SCFH)	139.232	88.887	112.810	73.833	91.724	90.251
Fraction of 0.6 L_a (percent)	87.14%	55.63%	70.60%	46.21%	57.41%	56.48%
AL Min Path (SCFH)	54.908	42.093	42.957	38.485	37.353	35.516
Fraction of 0.6 L_a (percent)	34.36%	26.34%	26.89%	24.09%	23.38%	22.23%

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

No LLRT components on an extended frequency exceeded their administrative limits over the last two refueling outages at BSEP Units 1 and 2.

BSEP Type B and C Component Performance:

The percentage of the total number of BSEP Unit 1 Type B tested components that are on 120-month extended performance-based test intervals is 100%.

The percentage of the total number of BSEP Unit 1 Type C tested components that are on 60-month extended performance-based test intervals is 56.8%.

The percentage of the total number of BSEP Unit 2 Type B tested components that are on 120 month extended performance-based test intervals is 100%.

The percentage of the total number of BSEP Unit 2 Type C tested components that are on 60 month extended performance-based test intervals is 60.2%.

3.7 Operating Experience

During the performance 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 BSEP Primary Containment, the following site specific and industry events have been evaluated for impact on BSEP:

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

Each of these areas is discussed in detail in Sections 3.7.1 through 3.7.5, respectively.

3.7.1 IN 1992-20, "Inadequate Local Leak Rate Testing"

The NRC issued IN 92-20 to alert licensees of problems with local leak rate testing two-ply stainless steel bellows used on piping penetrations at four different plants: Quad Cities Nuclear Power Station, Dresden Nuclear Station, Perry Nuclear Power Plant and the Clinton Station. Specifically, LLRTs could not be relied upon to accurately measure the leakage rate that would occur under accident conditions since, during testing, the two plies in the bellows were in contact with each other, restricting the flow of the test medium to the crack locations. Any two-ply bellows of similar construction may be susceptible to this problem. The common issue in the four events was the failure to adequately perform local leak rate testing on different

penetration configurations leading to problems that were discovered during ILRT tests in the first three cases.

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

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

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

Discussion

IN 1992-20 is not applicable to BSEP Units 1 or 2. There are no steel bellows installed as containment isolation barriers. In addition, all local leak rate testing methods have been verified to account for all possible leakage paths, including those through gasketed flanges. In addition, all isolation valves that have been credited with maintaining a water seal and therefore exempt from Appendix J testing have been verified to have lines that terminate below the minimum suppression pool level.

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

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

Discussion

In May of 1999, BSEP Unit 2 identified three areas in the drywell liner where corrosion had penetrated the liner. These areas were at the 18, 56, and 70-foot elevations.

18-Foot Elevation Defect Description

The drywell liner plate at the 18-foot elevation is constructed of 5/16-inch thick ASTM A-516, Grade 60 carbon steel plate, backed by approximately 6 feet of concrete, and coated with approximately 9-13 mils of Keeler and Long epoxy paint. The defect on the 18-foot elevation was initially identified as a broken coating blister exceeding acceptance limits with corrosion products visible through the break in the coating. The blister and corrosion products were removed to determine if sound metal was present below the surface. After removal, a 5/16-inch

diameter hole cylindrical through-wall indication was identified, with an adjoining area of approximately 1-inch in diameter exhibiting surface corrosion which had been under the coating. A small wire was inserted into the hole to a depth of 7/8-inch, indicating the presence of a 9/16-inch deep void in the concrete behind the defect in the liner plate.

Surface corrosion products and coatings were removed from the area, and a general visual examination was performed. Subsequent ultrasonic testing was performed in all directions immediately adjacent to the defect. Nominal metal thickness readings were obtained in all directions except for one subsurface indication. It connected to the through-wall defect and extended in the 8:00 direction (i.e., slightly below horizontal) for approximately 3/4-inch. The indication was approximately 1/4-inch wide and showed a reduced thickness of approximately 1/8-inch on the back of the plate.

During repairs, a metal burr was used to enlarge the opening as required to reach sound metal and to prepare a cavity suitable for welding. This resulted in an opening in the metal of approximately 3/4-inch by 2 inches. The subsurface defect appeared to be rust stained metal, with little or no powdered corrosion products as had been removed from the through-wall opening. The concrete was white, with only a light corrosion stain on the surface of the void. It was not filled with corrosion products. A small amount of concrete was removed to permit installation of a metal backing strip for the repair weld, and the subsurface concrete was sound, and white with no apparent cracking or other damage.

Root Cause of 18-Foot Elevation Defects

Pitting on the liner propagating through the liner wall caused the defects observed on the 18-foot elevation of the containment liner. This was primarily caused by corrosion which went undetected in previous containment liner examinations. Prior inspections noted the presence of corrosion; however, the observed defects seemed to meet the acceptance criteria. The inspection procedures exhibited weaknesses in requiring probing of visual indications that meet visual acceptance limits. A secondary cause of the corrosion was localized coating breaks which exposed the bare steel containment liner to oxygen and moisture. The breaks in the coating could have been caused by local mechanical damage. The moisture which accumulated on the drywell liner was comprised of chlorides from salt air and made contact with the liner through a break in the coating or osmotic blistering. The area behind the corrosion product buildup stored moisture for continuous exposure. The corrosion was also provided an oxygen rich environment during refueling outages (i.e., 21 percent oxygen), with long exposure provided during a yearlong outage in 1992 to1993.

56-Foot Elevation Defects Description

The cluster of defects located on the 56-foot elevation was the largest defect area identified but was unlike the defects on the 18 and 70-foot elevations. Therefore, it was evaluated separately. The drywell liner plate at the 56-foot elevation is constructed of 5/16-inch thick ASTM A-516, Grade 60 carbon steel plate, backed by approximately 6 feet of concrete and coated with approximately 9 to 13 mils of Keeler and Long epoxy paint. This area was identified by the presence of fresh rust stains streaming down the drywell liner from a cluster of blisters. The blisters and corrosion products were removed to determine if sound metal was present below the surface. Eight small pits were discovered. Additionally, there was a pronounced bulge in the liner at the exact location of those defects. Visual examination of the pits revealed subsurface corrosion in the plate at a shallow depth. The coatings were removed and ultrasonic testing was performed in the area. The depth of sound metal adjacent to the pits averaged

approximately 0.100 inches, indicating a significant metal loss on the backside of the plate. A lamination in the steel plate was initially suspected. Further ultrasonic testing was performed to determine the extent of the subsurface damage and an area of sound metal was found in all directions from the defects.

Two small sections of liner plate were removed to permit visual examination, one containing a cluster of five of the defects and another in the estimated location of a retaining stud behind the liner. A large corrosion product deposit was visible through each of these openings, indicating further plate removal was required. The Nelson stud which had been welded to the back of the liner had been damaged by corrosion, which severed its connection with the liner.

A section of liner, approximately 7 inches tall by 10 inches wide, was then removed. A large corrosion deposit was found intact behind the plate. This deposit was bright red in the location of the largest cluster of pits, indicating fresh corrosion activity. The color faded toward the edges, indicating less recent activity. The back side of the plate exhibited a large cavity resulting from the corrosion, which thickness similar to the readings obtained before using the ultrasonic testing. The maximum corrosion deposit thickness was at the location of the pits, gradually tapering toward the edges.

The concrete just beyond the edges of the deposit were clean and showed no evidence of rust stain, moisture or other damage. The corrosion deposit appeared localized. The corrosion deposit was carefully removed from the surface of the concrete. In the center of the deposit, where the maximum corrosion had occurred, a void was found in the concrete which contained some irregularly shaped foreign material. The concrete material was carefully removed and portions of a glove were identified, which had apparently fallen into the concrete during construction was extracted. The glove material was in direct contact with the corrosion deposit which contacted the liner. The pit location was directly in front of the area containing the glove as well. Further excavation was performed until sound concrete was revealed. No cracks were found in the concrete and no voids or rust stains remained in the cavity after excavation.

The corrosion deposit debris was examined and no sound metal was identified. The original plate material had been completely converted to corrosion products; ruling out the initial theory of lamination in the plate. The low thickness readings of the plate material resulted solely from metal loss due to corrosion from the back side of the plate.

Approximately 2 inches of the 8-inch long by 1/2-inch diameter Nelson stud had been consumed by corrosion. The excavation of the adjacent concrete exposed about 2 inches of the remaining portion of the stud, permitting welding of an extension during repairs. The remainder of the stud encased in concrete exhibited no corrosion products or staining and there was no gap between the stud and the concrete. The corrosion damaged portion had been completely removed. The maximum cavity depth in the concrete was approximately 3.5 inches. Adjacent studs in each direction were checked by ultrasonic testing and determined to be in contact with the liner plate. Ultrasonic testing of a four-square feet area surrounding the defect area was performed to assure that the defects were completely identified and repaired. No corrosion stains, debris or other indication of corrosion beyond the single location was found.

<u>Root Cause of 56-Foot Elevation Defects</u>

Pitting on the liner propagating through the liner wall caused the defects observed on the 56-foot elevation of the containment liner. This was primarily caused by corrosion which was not detected in its earliest stages, since the corrosion was not visible during the previous

inspection. The corrosion initiated as general corrosion behind the liner plate and initially did not penetrate the coated surface. General corrosion propagated through the thin remaining liner plate since the previous inspection. The corrosion rate accelerated once perforation occurred due to availability of moisture from the coated side of liner. This resulted in corrosion product buildup which ultimately bulged the liner. Moisture inside the drywell condensed on the surface of the liner, absorbing chlorides from the salt air. Moisture passed through perforations initiated from the back side of the plate, accelerating the corrosion rate. On the concrete side of the liner plate, void and debris in the concrete wicked moisture from the concrete for long periods of time after initial construction, creating conditions for initiation of general corrosion.

<u>70-Foot Elevation Defects Description</u>

The drywell liner plate at the 70-foot elevation is constructed of 5/16-inch thick ASTM A-516, Grade 60 carbon steel plate, backed by approximately 4 feet of concrete and coated with approximately 9 to 13 mils of Keeler and Long epoxy paint. The defect identified on the 70-foot elevation was also identified as a broken blister but was of a smaller size. The diameter of the corrosion deposit at the surface was approximately 1/4-inch, tapering down to 1/8-inch in the bottom of the pit. A grinder was used to prepare a cavity for welding. When the grinder contacted the indication, the corrosion products disintegrated, revealing a small through-wall defect 1/8-inch in diameter, 5/16-inch deep from the surface of the plate. No cavity was present in the concrete.

After coatings were removed adjacent to the defect, ultrasonic testing was performed indicating full metal thickness in all directions except for one area extending downward from the pit for approximately 1 inch. This area was approximately 1/8-inch wide and 1/16-inch deep on the back side of the plate.

The area was excavated to prepare a cavity for welding and to remove the area with reduced thickness. The exposed concrete exhibited rust staining but was dry and sound. No indication of moisture was present.

<u>Root Cause of 70-Foot Elevation Defects</u>

Pitting on the liner propagating through the liner wall caused the defects observed on the 70-foot elevation of the containment liner. This was primarily caused by corrosion which went undetected in previous containment liner examinations. Prior inspections noted the presence of corrosion; however, the observed defects seemed to meet the acceptance criteria. The inspection procedures exhibited weaknesses in requiring probing of visual indications that meet visual acceptance limits. A secondary cause of the corrosion was localized coating breaks which exposed the bare steel containment liner to oxygen and moisture. The breaks in the coating could have been cause by local mechanical damage. The moisture which accumulated on the drywell liner was comprised of chlorides from salt air and contacted the liner through a break in the coating or osmotic blistering. The area behind the corrosion product buildup stored moisture for continuous exposure. The corrosion was also provided an oxygen rich environment during refueling outages (i.e., 21 percent oxygen), with long exposure provided during a yearlong outage in 1992 to 1993.

<u>Repair Activities</u>

All liner repairs were completed during the 1999 Unit 2 refueling outage. This includes restoring the liner plate, anchor stud, and protective coating. Each area was given a local leak rate

pressure test with all areas testing satisfactorily. Ultrasonic testing of the defect areas on the 18-foot and 56-foot elevation was performed and no wall thinning or new indications were observed. Ultrasonic thickness of observed bulged areas previously identified on the containment liner were performed with no wall thinning observed.

3.7.3 IN 2010-12, "Containment Liner Corrosion"

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

Discussion

During the performance of containment inspections during the 2008 Unit 1 refueling outage, a VT-1 visual examination revealed two bulged areas in the 1-X-2 penetration sleeve. This is the drywell penetration sleeve associated with the personnel airlock. Based on a review of the examination data from previous outages, these two bulged areas were not previously recorded. Based on the thickness readings on one of the bulged areas, localized areas (i.e., within the examination area) were determined to be below the minimum design wall thickness. As a result, a more comprehensive ultrasonic thickness examination of the entire 1-X-2 penetration sleeve was conducted. This additional UT examination identified several discrete locations, which existed over less than 3 percent of the sleeve surface area, that were below the established minimum design wall thickness.

During the performance of primary containment inspections during the 2007 Unit 2 refueling outage, bulging was identified in the drywell airlock penetration sleeve 2-X-2. An ultrasonic thickness examination of the bulged area was performed and thicknesses below the acceptance criteria were found. The emphasis during 2007 Unit 2 refueling outage was evaluating minimum wall thickness based on newly detected bulges and pitting observed on the inside diameter of the sleeve.

A lack of rigor with respect to fully understanding and characterizing the degradation mechanism caused areas at or below minimum wall thickness to go undetected for two cycles. Because of previous lessons learned, a VT-1 visual examination of the 1-X-2 sleeve was performed during the 2008 Unit 1 refueling outage. The VT-1 visual examination is an enhanced visual examination method specified in the ASME Code, Section XI. Due to this enhanced visual examination method, areas of concern not identified during 2004 Unit 1 refueling outage were identified. Once identified, thickness readings using the static and dynamic ultrasonic scan methods were performed on the areas of concerned. For clarification, static readings are taken at the intersect points of the grid. The dynamic scan is performed by sweeping the transducer over the surface within the grid lines. Like the enhanced visual examination, the use of the dynamic scan method (to supplement the static readings) was based on lessons learned. The use of these enhanced examination methods assisted in identifying areas of wastage not observed during the 2004 Unit 1 refueling outage. It is apparent that if these enhanced examination methods were utilized during the 2004 Unit 1

refueling outage, the adverse condition would have been fully bounded and corrective actions implemented in a timelier manner.

Penetration sleeve 1-X-2 was considered to be operable, but degraded, with an interim use-as-is qualification until the next refueling outage. This operability evaluation was acceptable to all operating modes. The following actions were completed prior to startup:

- Repair the area of the boat sample. This area was defined by engineering and the repair performed in accordance with the applicable requirements of Article IWA-4000 (1992 Edition with 1992 Addenda).
- Repair the low reading area (<0.11") identified during the manual scan ultrasonic thickness examinations. This area was defined by engineering and the repair performed in accordance with the applicable requirements of Article IWA-4000 (1992 Edition with 1992 Addenda).
- The repaired areas were tested at 50 psig in accordance with the applicable requirements of Article IWE-5000 (1992 Edition with 1992 Addenda) and 10 CFR 50, Appendix J, Option B. Measured leakage rate was 0.00 standard cubic feet per hour (SCFH).

The Unit 1 penetration sleeve (1-X-2) was replaced during the 2010 Unit 1 refueling outage and the Unit 2 penetration sleeve (2-X-2) was replaced during the 2015 Unit 2 refueling outage.

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

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

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

Each test connection consists of a small carbon or stainless-steel tube (less than 1-inch diameter) that penetrates through the back of the channel and is seal-welded to the channel steel. The tube extends up through the concrete floor slab to a small access (junction) box embedded in the floor slab. The steel tube, encased in a pipe, projects up through the bottom

of the access box with a threaded coupling connection welded to the top of the tube, allowing for pressurization of the leak-chase channel. After the initial tests, steel threaded plugs or caps are installed in the test tap to seal the leak-chase volume. Gasketed cover plates or countersunk plugs are attached to the top of the access box flush with the containment floor. In some cases, the leak-chase channels with plugged test connections may extend vertically along the cylindrical shell or liner to a certain height above the floor.

Discussion

The BSEP Containment Structures are not constructed with Leak-Chase Channel Systems for the portion of liner that is made inaccessible by concrete.

The floor of containment is constructed with a slope away from the steel liner and concrete floor interface towards the containment floor drain sumps. Additionally, the original construction at the interface of the liner and concrete was designed with an asphaltic moisture barrier/seal to prevent moisture intrusion below grade.

In 1993 this interface was evaluated for each unit. Areas of liner degradation at the interface of the liner and concrete floor were noted. Concrete was excavated and the degradation was found limited to the interface and did not extend beyond the installed asphaltic seal. The degraded liner was repaired by welding. The moisture barrier/seal was also re-designed to further re-direct moisture away from the liner and concrete floor interface.

Inspection of the moisture barrier of each operating unit is included within the scope of the ASME Section XI Subsection IWE ISI Containment Inspection Program.

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

The NRC staff identified several instances in which containment shell or liner moisture barrier materials were not properly inspected in accordance with ASME Code Section XI, Table IWE-2500-1, Item E1.30. Note 4 (i.e., Note 3 in editions before 2013) for Item E1.30 under the "Parts Examined" column states, "Examination shall include moisture barrier materials intended to prevent intrusion of moisture against inaccessible areas of the pressure retaining metal containment shell or liner at concrete-to-metal interfaces and a metal-to-metal interfaces which are not seal welded. Containment moisture barrier materials include caulking, flashing and other sealants used for this application."

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

Discussion:

The condition identified in RIS 2016-07 was evaluated for applicability at BSEP. As a result, the BSEP Containment ISI Program was updated to perform the following:

- Identify all specific locations within each containment where moisture barriers exist.
- For all locations identified where there is no moisture barrier present or where the condition of the moisture barrier had degraded such that moisture intrusion behind the

joint could occur if the joint were exposed to water, specific actions were taken to mitigate the situation and to perform the inspections required by ASME Section XI at a frequency concurrent with IWE-2500-1 Examination Category E-A, Item E1.30.

- Verify that procedures for performing examinations of the containment moisture barrier in accordance with ASME Section XI IWE-2500-1 Examination Category E-A, Item E1.30 contain sufficient information pertaining to the scope and acceptance standards for visual examination of all types of moisture barriers at each site.

When this condition was identified, BSEP was in Interval 4 for the Containment ISI Program. The 2018 Unit 1 refueling outage and the 2017 Unit 2 refueling outage were the last outages remaining in the interval where full compliance with the moisture barrier periodic examination requirements was possible. The results of these inspections are detailed in Section 3.7.6 of this submittal.

3.7.6 Results of Recent Containment Inspections

Primary Containment Coatings Condition Assessment Unit 1 2016 Refueling Outage

The general condition of the primary containment was satisfactory. The coatings observed in the Drywell and Torus appeared well adhered with minimal areas of degradation. Understanding that mechanical damage, staining, and uncoated surfaces exists; the coatings on the vessel walls and structures, systems and components exhibited overall good adherence. Four recordable conditions were identified in the Drywell with greater than 1 square foot of minor flaking; however, the majority of the area still exhibited well coated and protected surfaces. The ring header coatings were in excellent condition, as was the Dome; both see minimal personnel activity.

The degradation of the coatings was caused by contact and/or mechanical damage. Exposed and unpainted metal can corrode during outage time while the nitrogen purge is discontinued. During the operating cycle, the nitrogen purge provides protection from continued oxidation of the metal. Coatings not mechanically damaged or disturbed exhibited good adhesion, especially surfaces out of reach, where physical contact does not occur.

The recordable conditions included a previous area under the vessel on the carousel, as well as spot locations on 17-foot and 52-foot elevations showing signs of initial peeling (i.e., all less than 1 square foot of affected area). On the -5 foot elevation, a single chipped paint location was identified on the liner by inspectors. All of the areas of degradation were entered into the Unqualified Coatings Exempt Log to be monitored in future outage walkdowns for worsening conditions, and potentially to be removed if needed. The Unqualified Coatings margin was well below the limit for the Maintenance Rule against the ECCS strainer. Following The 2012 Unit 1 refueling outage, the Unqualified Coatings as a percentage of MR a(1) limit was 60.3 percent.

Primary Containment Coatings Condition Assessment Unit 1 2018 Refueling Outage, Spring 2018

The overall general condition of the Service Level (SL-1) coatings was satisfactory. There were no observations of wide scale delamination caused by heat and/or humidity. Considering the environment of the drywell and the Torus/ring header, the well-adhered condition of the coatings is above average. There were areas with mechanical damage due to foot traffic, equipment paths, age and wear, however coatings around these locations of mechanical damage were

tightly adhered. Service Level I coatings in the drywell elevations -5-foot, 17-foot, 38-foot, 67-foot and 80-foot were in a satisfactory condition. The SL-1 coatings in the Torus and ring header were in a satisfactory condition. The SL-1 coatings on the Drywell Dome were in a satisfactory condition.

Any specific location which exhibited actual loss of adhesion, as evidenced by peeling or flaking was due to heat, humidity, and possibly surface conditions. However, very limited locations of loss of adhesion have been observed. The mechanical damage observed was due to the refuel outage traffic which is necessary to conduct walkdowns, inspections and repairs. The degraded coatings trend for the Service Level 1 coatings in the BSEP Unit 1 containment is maintaining. The exempt coatings log for Unit 1 tracks the volume of degraded coatings over the outages. The unqualified coatings volume following the Unit 1 2018 refueling outage is 60.5 percent of the allowed volume.

<u>Primary Containment Coatings Condition Assessment Unit 2 2015 Refueling Outage</u>

The overall general condition of the SL-1 coatings in the drywell elevations including -5-foot, 17-foot, 38-foot, 52-foot, 67-foot, 80-foot, and the interior of the drywell dome were good with little change from the 2013 Unit 2 refueling outage. The SL-1 coatings exhibited good adhesion to the vessel walls and to the outer liner. There was no observation of new flaking, blistering, or cracking. Several legacy items were reviewed and photographed to show unchanged conditions to those of previous outages. These comparisons illustrate that degraded coating conditions are not worsening due to time and the temperature of a normal operating cycle in the primary containment environment. Mechanical damage is evident, especially on the 17' elevation, but not more severe. There were no new non-Service Level 1 coatings identified other than minor inclusions which were appropriately documented in exemption requests. Overall the SL-1 coatings remain intact, are functioning well, and are protecting the substrate surfaces.

The observed conditions of the SL-1 coatings include various degradations mechanisms including mechanical damage, flaking of paint due to loss of adhesion, staining due to external sources, and discoloration due to temperature and time. There were no new discoveries of extreme coatings degradation. The inclusion of the zinc based, cold galvanizing products applied to galvanized steel ductwork at the time of plant construction had a negative impact to the reduction of unqualified coating volume. Although this "coating" is not failing, nor degrading, zinc based, cold galvanizing products have never been tested to withstand a DBA. As such its inclusion as an unqualified coating is necessary. The overall amount of degraded coatings as monitored via the Coatings Exempt Log has increased during the Unit 2 2015 refueling outage from 2.324 cubic feet to 2.440 cubic feet.

The overall general condition of the SL-1 coatings in the Torus is good. This assessment includes the ring header and the Torus above the water line, as observed from the catwalk. The SL-1 coatings exhibited good adhesion to the structural walls with no apparent changes from past outage walkdowns. There was no observation of new flaking, blistering, or cracking. Several legacy items were reviewed and photographed to show unchanged conditions to those of previous outages. These comparisons illustrate that degraded coating conditions are not worsening due to time and temperature of the normal operating cycle in the primary containment environment. Mechanical damage is evident, especially on the catwalk framing and other support beams in the Torus, but not more severe. A new recordable condition was entered identifying tracked footprints and paint drips of Carboline 890N. Additionally, the Torus

coatings below the water line, specifically the liner coating, was 100% inspected during the Unit 2 2015 refueling outage. A total of 6421 pit defects in the coating were identified, characterized, and repaired. These defects were recoated with Bio-Dur 561 and are qualified as Service Level I coating. Overall, the Service Level 1 coatings remain intact and are functioning well.

There is minimal degradation in the ring header of the Torus; the coatings are in excellent shape. The main Torus liner coatings above the water line are also in good condition, but discolored and stained at some locations. The Torus coatings on structures above the water line have mechanical damage and some surfaces have had their coatings removed entirely (i.e., catwalk members). The Torus coatings below the water line exhibited very good adhesion. However, there is pitting in the coating exposing the steel liner surface. The observed pitting is evidence of the interaction of the coating with elements in the water with agitation initiating small defects, leading to some galvanic action. These initiation sites could be due to defects/contamination left on the surface prior to recoating, however incomplete surface preparation would have more widespread adhesion issues. Pitting in the Torus below the water line coatings is common throughout the industry.

Primary Containment Coatings Condition Assessment Unit 2 2017 Refueling Outage

The general condition in all locations of primary containment was satisfactory during the Unit 2 2017 refueling outage Coatings Condition Assessment. Coatings on all elevations and areas were assessed during the 100% walkdown and many photos were taken as to illustrate the overall generally good condition and good adhesion of the coatings. Specific areas of degradation were identified. The K&L 7145 / 7105 coating system applied over most vessel and containment structural surfaces during original construction is demonstrating good performance. The Carboline 890 coating system, applied to various SCCs and locations within primary containment, also exhibits good adhesion. Photos from the previous three outages were compared with existing conditions. The change to the state of the coatings is negligible. Areas previously identified as degraded showed no significant or noticeable change or worsening.

Two of the recordable conditions were observed as peeling and flaking. This degradation mechanism is due to the heat, humidity and time of the exposure to the environment of the Drywell. The overall successful adhesion of both coating systems is quite good.

Unit 1 2014 Refueling Outage Primary Containment Inspection

The purpose of the Primary Containment Inspection is to perform examinations to assess the general condition of the containment liner and concrete surfaces of the primary containment and to detect evidence of degradation that may affect structural integrity or leak tightness. During the 2014 Unit 1 Primary Containment Inspection, the following nonconformances were identified:

Item Group: DW-X1

Recordable Condition: Localized General Corrosion that Reduces the Bolt / Stud Cross-Sectional Area

Disposition: No loss of structural integrity

Item Group: DW-X-6-BC

Recordable Condition: Deformed or Sheared Threads

Disposition: 1 bolt and nut had damaged (Galled) threads. Replaced under Work Order (WO) 12076389

Item Group: SC-C3

Recordable Condition: Efflorescence (leaching)

Disposition: Not a structural concern

Item Group SC-C4

Recordable Condition: Efflorescence (leaching) and cracking

Disposition: Not a structural concern

Item Group: SC-ML-BWL

Recordable Condition: Excessive Corrosion or Pitting, Material Loss Identified

Disposition: All indications were found to be bounded by plant calculation 0RIP-1009, were cleaned, prepped, and re-coated per the direction of the coatings engineer.

Item Group: 1-SP-Vent-Header-Manway

Recordable Condition: Other Coating Distress (coated surfaces only)

Disposition: Coatings engineer determined nozzle internal and outside surfaces were satisfactory.

Item Group: SC-X-200A

Recordable Condition: Rust (coated surfaces only), Excessive Corrosion or Pitting, Surface Discontinuity or Irregularity

Disposition: Conditions evaluated as acceptable by Engineering based on details of findings and EER 94-0263.

Item Group: SC-X-200A-BC

Recordable Condition: Nut displayed evidence of arc strikes and galling of the flat on the inside face of nut.

Disposition: Equivalent nut evaluated as acceptable under Engineering Change (EC) 96051 and installed under WO 2076220.

<u>Item Group: SC-X-200B</u>

Recordable Condition: Rust (coated surfaces only), Excessive Corrosion or Pitting, Surface Discontinuity or Irregularity.

Disposition: Conditions evaluated as acceptable by Engineering based on details of findings and Engineering Evaluation Report (EER) 94-0263.

<u>Item Group: SC-X-206D (Exterior)</u>

Recordable Condition: Blistering (coated surfaces only), Other Material Distress.

Disposition: Blistered paint is not within the pressure boundary and end plate has drain hole per plant drawing F-02807. Component is acceptable per Engineering.

<u>Item Group: SC-X-210A (Exterior)</u>

Recordable Condition: Rust (coated surfaces only).

Disposition: There was no base metal degradation noted. Work Request 11619442 was generated to remove the rust and re-coat the penetration. Component is evaluated as acceptable by Engineering.

<u>Unit 1 2016 Refueling Outage Primary Containment Inspection</u>

The purpose of the Primary Containment Inspection is to perform examinations to assess the general condition of the containment liner and concrete surfaces of the primary containment and to detect evidence of degradation that may affect structural integrity or leak tightness. During the 2016 Unit 1 Primary Containment Inspection, the following nonconformances were identified.

<u>Item Group: DW-IMB</u>

Recordable Condition: Damage, Tear, Separation. Several areas of the moisture barrier were found to have gouges and separation from the interface of the metallic liner and concrete floor of containment.

Disposition: The recordable conditions were documented under Condition Report (CR) 2007293. The portion of the moisture barrier, the curbing, found with recordable conditions are not credited to prevent moisture intrusions and are not sealing surfaces. Therefore, the conditions are acceptable and repairs are planned for a future outage under WO 20065692

<u>Item Group: SC-ML-BWL (Bays 1-16)</u>

Recordable Condition: Excessive Corrosion or Pitting

Disposition: All identified pit indications were found to be bounded by plant calculation 0RIP-1009 and accepted by Engineering

Unit 2 2015 Refueling Outage Primary Containment Inspection

The purpose of the Primary Containment Inspection is to perform examinations to assess the general condition of the containment liner and concrete surfaces of the primary containment and to detect evidence of degradation that may affect structural integrity or leak tightness. During the 2015 refueling outage Primary Containment Inspection, the following nonconformances were identified.

Item Group: SC-C3, -17' S RHR room

Recordable Condition: Cracking, Distortion, Evidence of Corrosion Staining or Corrosion

Disposition: The subject pipe is not a containment penetration or part of the containment pressure boundary. The condition is notable and entered into Corrective Action Program (CAP) under CR 736103. Of the remaining indications there is no evidence of structural damage or degradation to warrant further evaluation.

Item Group: SC-C4, -17' N RHR room

Recordable Condition: Distortion, Evidence of Corrosion Staining or Corrosion

Disposition: The subject pipe is not a containment penetration or part of the containment pressure boundary. The condition is notable and entered into CAP under CR 736103. Of the remaining indications there is no evidence of structural damage or degradation to warrant further evaluation.

Item Group: SC-C2, -17' N CS room

Recordable Condition: Cracking, Distortion, Evidence of Corrosion Staining or Corrosion

Disposition: There is no evidence of structural damage or degradation sufficient to warrant further evaluation at this time.

Item Group: DW-ML-4

Recordable Condition: Other Coating Distress (coated surfaces only), Bulging of the Liner

Disposition: Based on the evaluated conditions and the actual findings during the VT-1 and UT exams the bulging conditions are acceptable by engineering evaluation. Reference CR 735266 and WO 13494663

Item Group: DW-ML-5

Recordable Condition: Other Coating Distress (coated surfaces only), Bulging of the Liner

Disposition: Based on the evaluated conditions and the actual findings during the VT-1 and UT exams the bulge conditions are acceptable by engineering evaluation. Reference CR 735266 and WO 13494663

<u>Item Group: DW-IMB</u>

Recordable Condition: Separation

Disposition: Moisture barrier separation condition documented under CR 735566 and repaired under WO 13495235

<u>Item Group: SC-ML-BWL (Bays 1-16)</u>

Recordable Condition: Excessive Corrosion or Pitting, Bulging of the Liner

Disposition: All identified pit indications were re-coated prior to Torus close out.

<u>Unit 2 2015 Refueling Outage – Torus Project – Desludging, Inspection and Coating Repair</u>

Underwater desludging, inspection and coating repair were performed in the BSEP Unit 2 Torus during the Unit 2 2015 Refueling Outage. The project goals were to (1) remove any accumulation of sludge or foreign material that might affect ECCS strainer operation; (2) improve water clarity for inspection, repair, and water quality purposes; (3) perform VT-1/VT-3 examinations of the Torus immersion area, including liner plates, downcomers, test channels and other designated components; and (4) perform coating repair on areas of the Torus.

The desludging effort concentrated primarily on the shell plates and test channels of the Torus. Components were desludged as necessary to perform examinations. Sludge accumulation on the floor and components was light and generally consistent with expectations for the plant's operating cycle (i.e., less than or equal to 1/4-inch). Only minor foreign material was noted in the Torus proper and none of the ECCS strainers.

Mechanical damage, spot corrosion and staining of the coating were evident. Of the 6,421 exposed substrate locations that exceeded Engineering's repairable criteria, 1,428 locations meeting or exceeding Engineering's reportable criteria (i.e., less than or equal to 37 mils) were noted.

Coating repairs were performed on locations identified during the inspections that met or exceeded the repairable criteria. A visual inspection was performed by a VT-1 / VT-2 Level II inspector on 100% of the coating repairs on the shell plates in the Torus. All final repairs appeared fully cured and tightly bonded to the substrate with no evidence of bleed-through, cracking, peeling or other deleterious effects.

Overall, the condition of the principal coating system in the inspected immersion area was good. Although numerous random localized failures have occurred, the majority of the coating is providing adequate protection of the base metal. With routine monitoring and periodic maintenance, it should continue to provide an adequate barrier protection.

Summary of Inspection Findings

Torus Shell Plates and Channels

In general, the principal coating system within the interior immersion area was noted to be in good condition. Surfaces of the Torus shell plates exhibited spot corrosion and mechanical damage. With the exception of four indications identified in Bay 16, metal loss from exposed substrate indications generally ranged from less than 37 mils to less than 70 mils. Intact coating adjacent to exposed substrate appeared tightly bonded.

Indication Exceeding Repair/Reportable Criteria

A cumulative total of 6,421 exposed substrate indications were identified on the Torus shell plating throughout the immersion area meeting the requirements for coating repair. This accounted for an approximate total affected area of 1,240 square inches.

While metal loss at the greater percent (i.e., greater than 77 percent) of the exposed substrate locations fell below the reportable guidelines established by Plant Engineering (i.e., greater than 37 mils) a total of 1,428 indications did exceed the guidelines. Indications with metal loss exceeding the acceptance criteria were reported to Engineering on a day by day basis.

Additionally, it should be noted that during diving activities four bulge indications were identified in close proximity to Torus penetrations. After site review, the following scope of work was completed:

1. Dry Film Thickness (DFT) readings were taken in the affected areas
2. UT grids at 1-inch square locations were penciled on the four affected areas
3. Diver support was provided for the UT examinations

Downcomers (Exterior Only)

Downcomer examinations were deferred in order to address inspection/repair of the large quantity of coating deficiencies/exposed substrate indications identified during examination of the Torus shell plates.

Quencher Support Flange Hardware

The inspections on the quencher support flange hardware were conducted to verify the presence of the connecting flange hardware. High resolution video was used to document these inspections. In general, all quencher support flange hardware was present and appeared in good condition. No further data or documentation will be provided nor was any such documentation or data collecting established as part of this work scope.

ECCS Inspections

As-left vide inspections were conducted on the ECCS Suction Strainers. These inspections were conducted to identify any foreign and/or fibrous material on the strainers themselves. High

resolution video was used to document these inspections. In general, no notable foreign material was identified on the inspected strainers.

Bay 7/8 Supports

Video inspections were performed on the Bay 7 and Bay 8 component supports. High resolution video was used to document these inspections.

Coating Repair

Coating repair was performed on all exposed substrate locations identified during the qualitative inspections. Surface preparation for each repair was performed in accordance with site procedures using pneumatic grinders equipped with a 3M wheel, Bio-Dur 561, an underwater applied two-part epoxy, was then applied immediately following the surface preparation.

A total of 6,421 indications were repaired on the Unit 2 Torus shell plates. The total surface area of these repair locations was 24,469 square inches (i.e.,170 square feet).

A certified Level II coating inspector performed a visual inspection on all repairs for final acceptance. All final repairs appeared fully cured and tightly bonded to the substrate and the surrounding coating with no evidence of bleed-through, cracking, peeling or other unfavorable effects. Dry film thickness readings were taken on a representative sample (i.e., less than 25 percent) of the repairs, and all final repairs were found to be within acceptable range (i.e., 10 to 40 mils). The average dry film thickness for these repairs was 26.3 mils.

Sludge and Debris

Sludge accumulation in the Torus was considered light. Within a given Bay, the heaviest deposits were typically recorded near the invert weld seams of the Torus shell. Sludge depths averaged a nominal 1/8-inch to 1/4-inch with isolated areas up to 1-inch deep. This light accumulation along with the loose adhesion of the sludge material to the coating system resulted in the small percentage of the Unit 2 2017refueling outage dive time (i.e., less than 22 percent) spent in support of the desludge effort. As a direct result of the limited time required to support the desludge effort, nearly all of the ISI examinations were completed. While all of the bulk sludge was removed from the wetted surfaces of the Torus shell plates no sludge was removed from the downcomers and ECCS suction strainers.

Coating and Corrosion Conditions

The condition of the inspection immersion area principal coating system on the shell plates were in good condition, with greater percentage of the inspected coated surface exhibiting little to no coating damage or degradation. Although numerous random small localized failures have occurred, the majority of the coating was providing excellent protection of the base metal. In concurrence, the results of the Unit 2 2017 refueling outage inspection strongly supported the conclusion that the corrosion rates remained low.

ECCS Strainer Conditions

Foreign material only inspections were performed on all ECCS Suction strainers. No foreign material was noted. The strainers appeared to be in good condition with a moderate sludge film on the strainer mesh.

Unit 2 2017 Refueling Outage Primary Containment Inspection

The purpose of the Primary Containment Inspection is to perform examinations to assess the general condition of the containment liner and concrete surfaces of the primary containment and to detect evidence of degradation that may affect structural integrity or leak tightness. During the 2017 Refueling Outage Primary Containment Inspection, the following nonconformances were identified.

Item Group: 2-DW-ML-4

Recordable Condition: While performing the general visual examination on the containment liner an area of material distress (i.e., depression/displacement) was noted at approximately 265 degrees azimuth at the 42'-foot elevation.

Disposition: Since the distressed area is localized and the remaining wall thickness exceeds the calculated minimum localized liner wall thickness this condition was determined to be acceptable by evaluation and no repairs were required.

3.7.7 BSEP Containment Modifications - Hardened Containment Venting System (HCVS) Modification

On March 19, 2013, the NRC Commissioners directed the staff per Staff Requirements Memorandum (SRM) for SECY-12-0157 (i.e., Reference 36) to require licensees with Mark I and Mark II containments to "upgrade or replace the reliable hardened vents required by Order EA-12-050 (i.e., Reference 37) with a containment venting system designed and installed to remain functional during severe accident conditions." In response, the NRC issued Order EA-13-109, Issuance of Order to Modifying Licenses with Regard to Reliable Hardened Containment Vents Capable of Operation Under Severe Accident Conditions (i.e., Reference 38) on June 6, 2013. The Order required that licensees of BWR facilities with Mark I and Mark II containment designs ensure that these facilities have a reliable hardened vent to remove decay heat from the containment and maintain control of containment pressure within acceptable limits following events that result in the loss of active containment heat removal capability while maintaining the capability to operate under severe accident (SA) conditions resulting from an Extended Loss of AC Power (ELAP).

The Order requirements are applied in a phased approach where:

- Phase 1 involved upgrading the venting capabilities from the containment wetwell to provide reliable, severe accident capable hardened vents to assist in preventing core damage and if necessary to provide venting capability during severe accident conditions. (Completed no later than startup from the second refueling outage that begins after June 30, 2014 or June 30, 2018, whichever comes first.)

- Phase 2 involves providing additional protections for severe accident conditions through installation of a reliable, severe accident capable drywell vent system or the development of a reliable containment venting strategy that makes it unlikely that a licensee would need to vent from the containment drywell during severe accident

conditions. (Completed no later than startup from the first refueling outage that begins after June 30, 2017, or June 30, 2019, whichever comes first.)

No containment or containment isolation system modifications were required at BSEP to comply with the NRC Orders. The HCVS utilizes CAC system valves CAC-V7 and CAC-V216 for containment isolation. CAC-V7 and CAC-V216 are air operated valves (AOVs) that are air-to-open and spring-to-close. A solenoid operated valve (SOV) must be energized to allow the motive air to open the valve from the main control room location. CAC-V7 and CAC-V216 have a safety-related function to maintain the containment pressure boundary during a DBA and are tested as required by 10 CFR 50, Appendix J. Although these valves are shared between the CAC and HCVS, separate control circuits are provided to each valve. Specifically, the CAC control circuit will be used during all design basis operating modes including all design basis transients and accidents.

Cross flow potential exists between the HVCS and the Standby Gas Treatment System (SBGT). CAC valves CAC-V8 and CAC-V172 function as boundary valves within the SBGT system. Valves CAC-V8 and CAC-V172 are CIVs with a safety-related function to maintain the containment pressure boundary during a DBA. These valves are tested and will continue to be tested for leakage under 10 CFR 50, Appendix J as part of the containment boundary. These valves therefore prevent cross-flow from the Severe Accident Wetwell Vent (SAWV) pipe to the SBGT system.

3.8 License Renewal Aging Management

By letter dated October 18, 2004, Carolina Power & Light Company (CP&L) requested renewal of the operating licenses issued in Section 104b (i.e., Operating License Nos. DPR-71 and DPR-62) of the Atomic Energy Act of 1954, as amended, for BSEP Units 1 and 2 for a period of 20 years (i.e., Reference 39). The NRC issued the Renewed Operating Licenses on June 26, 2006 (i.e., Reference 52). The Renewed Operating License expiration dates are midnight on September 8, 2036, for Unit 1 and midnight on December 27, 2034, for Unit 2. The following Aging Management Programs are applicable to this LAR.

3.8.1 Aging Management Programs

Appendix J Program

The 10 CFR Part 50, Appendix J Program consists of monitoring of leakage rates through containment liner/welds, penetrations, fittings and access openings to detect degradation of the pressure boundary. Corrective actions are taken if leakage rates exceed acceptance criteria. This Program is implemented in accordance with Option B (i.e., performance-based leak testing) of 10 CFR Part 50, Appendix J; RG 1.163; and NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J." This Program is consistent with the corresponding program described in NUREG-1801 (i.e., Reference 51).

ASME Section XI, Subsection IWE Program

The ASME Section XI, Subsection IWE Program consists of periodic inspection of steel containment components for signs of degradation, assessment of damage, and corrective actions. This Program is in accordance with ASME Section XI, Subsection IWE, and in accordance with 10 CFR 50.55a. The ASME Section XI, Subsection IWE Program is consistent with the corresponding program described in NUREG-1801.

ASME Section XI, Subsection IWL Program

The ASME Section XI, Subsection IWL Program is credited for the aging management of accessible and inaccessible pressure retaining Primary Containment concrete for both BSEP units. The BSEP containment structures do not use prestressing tendons. Therefore, ASME Section XI, Subsection IWL rules regarding post-tensioning systems are not applicable. This Program is in accordance with the ASME Section XI, Subsection IWL and in accordance with 10 CFR 50.55a. The ASME Section XI, Subsection IWL Program is consistent with the corresponding program described in NUREG-1801 with the exception that requirements associated with a post-tensioning system are not applicable.

Protective Coating Monitoring and Maintenance Program

The Protective Coating Monitoring and Maintenance Program prevents clogging of the ECCS suction strainers and containment spray nozzles by monitoring the condition of coatings and assuring that the quantity of damaged, degraded, or unqualified coatings inside the Primary Containment of each unit which could detach during a LOCA remains below established design limits.

The Program administrative controls have been enhanced to: (1) add a requirement for a walk-through, general inspection of containment areas during each refueling outage, including all accessible pressure-boundary coatings not inspected under the ASME Section XI, Subsection IWE Program, (2) add a requirement for a detailed, focused inspection of areas noted as deficient during the general inspection, (3) assure that the qualification requirements for persons evaluating coatings are consistent among the Service Level I coating specifications, inspection procedures, and application procedures, and meet the requirements of ANSI N 101.4, "Quality Assurance for Protective Coatings Applied to Nuclear Facilities," and (4) document the results of inspections and compare the results to previous inspection results and to acceptance criteria. The Program is consistent with the corresponding program described in NUREG-1801 with the exception that the Program is not credited for preventing corrosion of primary containment components.

3.9 NRC SER Limitations and Conditions

3.9.1 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 3.9.1-1 were satisfied:

Table 3.9.1-1: NEI 94-01, Revision 2-A, Limitations and Conditions	
Limitation/Condition **(From Section 4.0 of SE)**	**BSEP 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.)	BSEP will utilize the definition in NEI 94-01 Revision 3-A, Section 5.0. This definition has remained unchanged from Revision 2-A to Revision 3-A of NEI 94-01.
The licensee submits a schedule of containment inspections to be performed prior to and between Type A tests. (Refer to SE Section 3.1.1.3.)	Reference Sections 3.6.3 and 3.6.4 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 3.6.3 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. No containment or containment isolation system modifications were required at BSEP to comply with the NRC Orders for FLEX.
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.)	BSEP 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, BSEP 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.

Table 3.9.1-1: NEI 94-01, Revision 2-A, Limitations and Conditions	
Limitation/Condition <u>(From Section 4.0 of SE)</u>	**<u>BSEP Response</u>**
For plants licensed under 10 CFR 52, applications requesting a permanent extension of the ILRT surveillance interval to 15 years should be deferred until after the construction and testing of containments for that design have been completed and applicants have confirmed the applicability of NEI 94-01, Revision 2, and EPRI Report No. 1009325, Revision 2, including the use of past containment ILRT data.	Not applicable. BSEP was not licensed under 10 CFR 52.

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

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

<u>Topical Report Condition 1</u>

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

Response to Condition 1

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

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

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

- ISSUE 3 - Use of the allowed 9-month extension for eligible Type C valves is only authorized for non-routine emergent conditions with exceptions as detailed in NEI 94-01, Revision 3-A, Section 10.1.

Response to Condition 1, ISSUE 1

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

Response to Condition 1, ISSUE 2

When the potential leakage understatement adjusted Type B and C MNPLR total is greater than the BSEP administrative leakage summation limit of 0.50 L_a, but less than the regulatory limit of 0.6 L_a, then an analysis and determination of a corrective action plan shall be prepared to restore the leakage summation margin to less than the BSEP leakage limit. The corrective action plan shall focus on those components which have contributed the most to the increase in the leakage summation value and the manner of timely corrective action, as deemed appropriate, that 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

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

Topical Report Condition 2

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

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

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

Response to Condition 2

Condition 2 presents two (2) separate issues that are required to be addressed as follows:

- ISSUE 1 - Extending the LLRT intervals beyond 5 years to a 75-month interval should be similarly conservative provided an estimate is made of the potential understatement and its acceptability determined as part of the trending specified in NEI TR 94-01, Revision 3, Section 12.1.
- ISSUE 2 - When routinely scheduling any LLRT valve interval beyond 60 months and up to 75 months, the primary containment leakage rate testing program trending or monitoring must include an estimate of the amount of understatement in the Type B and C total, and must be included in a licensee's post-outage report. The report must include the reasoning and determination of the acceptability of the extension, demonstrating that the LLRT totals calculated represent the actual leakage potential of the penetrations.

Response to Condition 2, ISSUE 1

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

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

Response to Condition 2, ISSUE 2

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

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

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

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

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

3.10 Conclusion

3.10.1 Adoption of NEI 94-01 Revision 3-A

NEI 94-01, Revision 3-A, dated July 2012, and the conditions and limitations specified in NEI 94-01, Revision 2-A, dated October 2008, describe an NRC-accepted approach for implementing the performance-based requirements of 10 CFR 50, Appendix J, Option B. It incorporated the regulatory positions stated in RG 1.163 and includes provisions for extending Type A intervals to 15 years and Type C test intervals to 75 months. NEI 94-01, Revision 3-A delineates a performance-based approach for determining Type A, Type B, and Type C containment leakage rate surveillance test frequencies. BSEP is adopting the guidance of NEI 94-01, Revision 3-A, and the conditions and limitations specified in NEI 94-01, Revision 2-A, for the BSEP 10 CFR 50, Appendix J testing program plan.

Based on the previous ILRTs conducted at BSEP, it may be concluded that the permanent extension of the containment ILRT interval from 10 to 15 years represents minimal risk to increased leakage. The risk is minimized by continued Type B and Type C testing performed in

accordance with Option B of 10 CFR 50, Appendix J and the overlapping inspection activities performed as part of the following BSEP inspection programs:

- ASME Section XI, IWE Examinations
- ASME Section XI, IWL Examinations
- Containment Maintenance Rule Inspections
- Primary Containment Coatings Program

This experience is supplemented by risk analysis studies, including the BSEP risk analysis provided in Attachment 6 of this submittal. The risk assessment concludes that increasing the ILRT interval on a permanent basis to a one-in-fifteen-year frequency is not considered to be significant since it represents only a very small change in the BSEP 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 2A (i.e., Reference 8), provided a risk impact assessment for optimized ILRT intervals up to 15 years, utilizing current industry performance data and risk informed guidance. NEI 94-01, Revision 3-A, Section 9.2.3.1 states that Type A ILRT intervals of up to 15 years are allowed by this guideline. The Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals, EPRI Report 1018243 (i.e., formerly TR-1009325, Revision 2A) 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 2A. 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 (i.e., Reference 1). The NRC staff finds that the Type A testing methodology as described in ANSI/ANS-56.8-2002 (i.e., Reference 14), and the modified testing frequencies recommended by NEI TR 94-01, Revision 2, serve to ensure continued leakage integrity of the containment structure. Type B and Type C testing ensures that individual penetrations are essentially leak tight. In addition, aggregate Type B and Type C leakage rates support the leakage tightness of primary containment by minimizing potential leakage paths.

For EPRI Report No. 1009325, Revision 2A (i.e., Reference 8), 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, An Approach to Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications (i.e., Reference 40) and RG 1.174 (i.e., Reference 7). The NRC staff, therefore, found that this guidance was acceptable for referencing by licensees proposing to amend their TS in regards to containment leakage rate testing, subject to the limitations and conditions noted in Section 4.2 of the SER.

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

4.2 Precedent

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

- Surry Power Station, Unit 1 (i.e., Reference 41)
- Donald C. Cook Nuclear Plant, Unit 1 (i.e., Reference 42)
- Beaver Valley Power Station, Unit Nos. 1 and 2 (i.e., Reference 43)
- Calvert Cliffs Nuclear Power Plant, Unit Nos. 1 and 2 (i.e., Reference 44)
- Peach Bottom Atomic Power Station, Units 2 and 3 (i.e., Reference 45)
- Comanche Peak Nuclear Power Plant, Units 1 and 2 (i.e., Reference 46)
- Catawba Nuclear Station, Units 1 and 2 (i.e., Reference 47)

- H. B. Robinson Steam Electric Plant, Unit No. 2 (i.e., Reference 48)
- Quad Cities Nuclear Power Station, Units 1 and 2 (i.e., Reference 49)
- Dresden Nuclear Power Station, Units 2 and 3 (i.e., Reference 50)

4.3 No Significant Hazards Consideration

Duke Energy Progress, LLC (Duke Energy) proposes to amend the Technical Specifications (TS) for Brunswick Steam Electric Plant (BSEP), Units 1 and 2 to allow extension of the Type A and Type C test intervals. The extension is based on the adoption of the Nuclear Energy Institute (NEI) 94-01, Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J, Revision 3-A and conditions set forth in Revision 2-A. Duke Energy has evaluated whether or not a significant hazards consideration is involved with the proposed amendment by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

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

Response: No.

The proposed activity involves the revision of the Brunswick Steam Electric Plant (BSEP) Units 1 and 2 Technical Specification (TS) 5.5.12, Primary Containment Leakage Rate Testing Program, to allow the extension of the Type A integrated leakage rate test (ILRT) containment test interval to 15 years, and the extension of the Type C test interval to 75 months. Per the guidance provided in Nuclear Energy Institute (NEI) 94-01, Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J, Revision 3-A, the current Type A test interval of 120 months (i.e., 10 years) would be extended on a permanent basis to no longer than 15 years from the last Type A test. The current Type C test interval of 60 months for selected components would be extended on a performance basis to no longer than 75 months. Extensions of up to nine months for Types A, B and C tests are permissible only for non-routine emergent conditions.

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

The change in Type A test frequency to once-per-fifteen-years, measured as an increase to the total integrated plant risk for those accident sequences influenced by Type A testing, based on the probabilistic risk assessment (PRA) is 4.98E-03 person-rem/year. for Unit 1 and 4.67E-03 person-rem/year. for Unit 2. Electric Power Research Institute (EPRI) Report No. 1009325, Revision 2-A states that a very small population dose is defined as an increase of less than 1.0 person-rem per year or less than 1 percent of the total population dose, whichever is less restrictive for the risk impact assessment of the extended ILRT intervals. This is consistent with the Nuclear Regulatory Commission (NRC) Final Safety Evaluation for NEI 94-01 and EPRI Report No. 1009325, Revision 2A. Moreover, the risk

impact when compared to other severe accident risks is negligible. Therefore, the proposed extension does not involve a significant increase in the probability of an accident previously evaluated.

In addition, as documented in NUREG-1493, "Performance-Based Containment Leak-Test Program," dated September 1995, Types B and C tests have identified a very large percentage of containment leakage paths, and the percentage of containment leakage paths that are detected only by Type A testing is very small. The BSEP Unit 1 and Unit 2 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) Boiler and Pressure Vessel (B&PV) Code, Section XI, Rules for Inservice Inspection of Nuclear Power Plant Components, Containment Maintenance Rule Inspections, Containment Coatings Program 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 (ILRT). Based on the above, the proposed test interval extensions do not significantly increase the consequences of an accident previously evaluated.

The proposed amendment also proposes administrative changes to the exceptions in Units 1 and 2 TS 5.5.12.c and f. TS exceptions 5.5.12.c reference NEI 94-01 Revision 0 and TS exceptions 5.5.12.f reference ANSI/ANS 56.8-1994. This change proposes to update the referenced documents in these two TS exceptions to reflect the adoption of NEI 94-01, Revision 3-A and ANSI/ANS 56.8-2002, accordingly. This administrative change does not impact any accidents previously evaluated.

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

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

   Response: No.

   The proposed amendment to the BSEP Units 1 and 2 TS 5.5.12, "Primary Containment Leakage Rate Testing Program," involves the extension of the BSEP, Units 1 and 2 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 proposes administrative changes to the exceptions in Units 1 and 2 TS 5.5.12.c and f. TS exceptions 5.5.12.c reference NEI 94-01 Revision 0 and TS exceptions 5.5.12.f reference ANSI/ANS 56.8-1994. This change proposes to update the referenced documents in these two TS exceptions to reflect the adoption of NEI 94-01, Revision 3-A and ANSI/ANS 56.8-2002, accordingly. This administrative change to the references listed in TS 5.5.12.c and f, does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

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

Response: No.

The proposed amendment to Unit 1 and Unit 2 TS 5.5.12 involves the extension of the BSEP Type A containment test interval to 15 years and the extension of the Type C to 75 months. 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 BSEP, Units 1 and 2. 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 Option B to 10 CFR 50, Appendix J and the overlapping inspection activities performed as part of ASME Section XI, and the 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 proposes administrative changes to the exceptions in Units 1 and 2 TS 5.5.12. Two exceptions listed in the Units 1 and 2 TS 5.5.12 contain references to revisions and years of the ANSI/ANS 56.8 and NEI 94-01. Units 1 and 2 TS 5.5.12 exception c references NEI 94-01, Revision 0 and Units 1 and 2 TS 5.5.12 exception f references ANSI/ANS 56.8-1994. This change proposes to update the referenced documents in these two TS exceptions to reflect the adoption of NEI 94-01, Revision 3-A and ANSI/ANS 56.8-2002, accordingly. This administrative change does not change how the unit is operated or maintained, thus there is no reduction in any margins of safety.

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

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

4.4 Conclusion

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

5.0 ENVIRONMENTAL CONSIDERATION

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

6.0 REFERENCES

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

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

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

4. ANSI/ANS 56.8-2002, "Containment System Leakage Testing Requirements," LaGrange Park, Illinois, November 2002

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

6. ANSI/ANS 56.8-1994, "Containment System Leakage Testing Requirements," dated August 4, 1994

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

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

9. NUREG/CR-2973, "Loss of DHR Sequences at Browns Ferry Unit One – Accident Sequence Analysis," Oak Ridge National Laboratory, May 1983

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

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

12. 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

13. 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 50, Appendix J (TAC No. ME2164)," dated June 8, 2012

14. Letter from D.C. Trimble (NRC) to Mr. W.R. Campbell (CP&L), "Issuance of Amendment No. 181 to Facility Operating License No. DPR-71 and Amendment No. 213 to Facility Operating License No. DPR-62 Regarding 10 CFR Part 50, Appendix J, Option B – Brunswick Steam Electric Plant, Units 1 and 2 (BSEP 95-0316) (TAC Nos. M93679 and M93680)." dated February 1, 1996

15. Letter from A.G. Hansen (NRC) to J.S. Keenan (CP&L), "Brunswick Steam Electric Plant, Unit 1 – Issuance of Amendment Regarding Containment Leakage Rate Testing Program (TAC No. MB3470)," dated March 6, 2002

16. Letter from B.L. Mozafari (NRC) to J.S. Keenan (CP&L), "Brunswick Steam Electric Plant, Unit 2 – Issuance of Amendment Regarding Containment Leakage Rate Testing Program (TAC No. MB3471)," dated November 21, 2002

17. Letter from B.L. Mozafari (NRC) to C.J. Gannon (CP&L), "Brunswick Steam Electric Plant, Unit Nos. 1 and 2 – Issuance of Exemption from 10 CFR Part 50, Appendix J (TAC Nos. MC4879 and MC4880)," dated March 9, 2005

18. Letter from B.L. Mozafari (NRC) to J. Scarola (CP&L), "Brunswick Steam Electric Plant, Units 1 and 2 – Issuance of Amendment on Primary Containment Leakage Rate (TAC Nos. MC8110 and MC8111)," dated February 8, 2006

19. Letter from B.L. Mozafari (NRC) to J. Scarola (CP&L), "Brunswick Steam Electric Plant, Unit Nos. 1 and 2 – Issuance of Amendment Regarding Main Steam Isolation Valve Leakage Limit (TAC Nos. MC8106 and MC8107), Dated March 2, 2006.)"

20. Letter S.N. Bailey (NRC) to B. Waldrep (CP&L), "Brunswick Steam Electric Plant, Units 1 and 2 – Issuance of Amendment Regarding Primary Containment Leakage Rate Testing Program (TAC Nos. MD6340 and MD6341)"

21. Letter from D.B. Vassallo (NRC) to E.E. Utley (CP&L), dated December 9, 1983

22. Letter from E.G. Tourigny (NRC) to L.W. Eury (CP&L), "Issuance of Amendment No. 136 to Facility Operating License No. DPR-71 and Amendment No. 166 to Facility Operating License No. DPR-62 – Brunswick Steam Electric Plant, Units 1 and 2, Regarding Containment Integrated Leak Rate Testing (TAC Nos. 73030 and 73031)"

23. Letter from E.D. Sylvester (NRC) to E.E. Utley (CP&L), Brunswick Steam Electric Plant, Units 1 and 2 "Technical Exemption from the Requirements of Appendix J," dated May 12, 1987

24. Letter from A. Schwencer (NRC) to J.A. Jones (CP&L), dated November 23, 1977

25. Letter from V. Stello, Jr. (NRC) to J.A. Jones (CP&L), dated November 8, 1977

26. Letter from R.A. Anderson (CP&L) to United States Nuclear Regulatory Commission Document Control Desk, "Brunswick Steam Electric Plant, Units 1 and 2 Dockets Nos. 50-325 & 50-324 / License Nos DPR-71 & DPR-62 Request for License Amendment Type A Integrated Leakage Rate Testing Schedule," dated October 19,1993

27. Letter from P.D. Milano (NRC) to R.A. Anderson (CP&L), "Issuance of Amendment No. 167 to Facility Operating License No. DPR-71 and Amendment No. 198 to Facility Operating License No. DPR-62 Regarding Containment Integrated Leak Rate Test – Brunswick Steam Electric Plant, Units 1 and 2 (TAC Nos. M88044 and M88045)," dated January 11, 1994

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

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

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

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

32. NEI 05-04, "Process for Performing Internal Events PRA Peer Review Process Guidelines," Revision 1

33. NEI 07-12, "Fire Probabilistic Risk Assessment (FPRA) Peer Review Process Guidelines," Revision 1

34. Calculation BNP-PSA-068, "BNP – PSA Model Peer Review F&O," Revision 7

35. Regulatory Guide 1.174, Revision 3, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," May 2018

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

37. NRC Order EA-12-050, Order Modifying Licenses with Regard to Reliable Hardened Containment Vents, dated March 12, 2012 (ML12054A694).

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

39. Letter from C. J. Gannon (Progress Energy) to United States Nuclear Regulatory Commission Document Control Desk, "Application for Renewal of Operating License," dated October 18, 2004

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

41. Letter to D. Heacock from S. Williams (NRC), Surry Power Station, Unit 1 - Issuance of Amendment Regarding the Containment Type A and Type C Leak Rate Tests, dated July 3, 2014 (ML14148A235)

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

43. 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)

44. 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)

45. 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)

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

47. Letter from M.D. Orenak (NRC) to K. Henderson, "Catawba Nuclear Station, Units 1 and 2 – Issuance of Amendments Regarding Extension of the Containment Integrated Leak Rate Test Intervals (CAC Nos. MF7265 and MF7266)," dated September 12, 2016 (ML16299A113)

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

49. Letter K.J. Green (NRC) to B.C. Hanson (Exelon Generation Company), "Quad Cities Nuclear Power Station, Units 1 and 2 – Issuance of Amendments Regarding Permanent Extension of Type A and Type C Leak Rate Test Frequencies (CAC Nos. MF9675 and MF9676; EPID L-2017-LLA-0220) (RS-17-051)," dated December 1, 2017 (ML17311A162)

50. Letter from R.S. Haskell (NRC) to B.C. Hanson (Exelon Generation Company), "Dresden Nuclear Power Station, Units 2 and 3 – Issuance of Amendments Regarding Permanent Extension of Type A and Type C Leak Rate Test Frequencies (CAC Nos. MF9687 and MF9688; EPID L-2017-LLA-0228) (RS-17-060)," dated June 29, 2018 (ML18137A271)

51. NUREG-1801, Generic Aging Lessons Learned (GALL Report)

52. Letter from Maurice Heath (NRC) to James Scarola (CP&L), "Issuance of Renewed Facility Operating License Nos. DPR-71 and DPR-62 for Brunswick Steam Electric Plant, Units 1 and 2, dated June 26, 2006 (ML061660358)

53. Letter from B.L. Mozafari (NRC) to Mr. J.S. Keenan (BSEP), “Brunswick Steam Electric Plant Units 1 and 2 – Issuance of Amendment Re: Extended Power Uprate (TAC Nos. MB2700 and MB2701),” dated May 31, 2002 (ML021430551)

Proposed Technical Specification Changes (Mark-Up) Unit 1

5.5.11 Safety Function Determination Program (SFDP) (continued)

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

5.5.12 Primary Containment Leakage Rate Testing Program

A primary containment leakage rate testing program shall establish requirements to implement the leakage rate testing of the primary containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B as modified by approved exemptions. This program shall be in accordance with the guidelines contained in ~~Regulatory Guide 1.163, September 1995~~ 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, as modified by the following exceptions:

a. The visual examination of concrete surfaces intended to fulfill the requirements of 10 CFR 50, Appendix J, Option B testing, will be performed in accordance with the requirements of and frequency specified by the ASME Section XI Code, Subsection IWL, except where relief has been authorized by the NRC.

b. The visual examination of the metallic shell, penetrations, and appurtenances intended to fulfill the requirements of 10 CFR 50, Appendix J, Option B, will be performed in accordance with the requirements of and frequency specified by the ASME Section XI Code, Subsection IWE, except where relief has been authorized by the NRC.

c. Following air lock door seal replacement, performance of door seal leakage rate testing with the gap between the door seals pressurized to 10 psig instead of air lock testing at P_a as specified in Nuclear Energy Institute Guideline 94-01, Revision ~~0~~3-A;

d. Reduced duration Type A tests may be performed using the criteria and Total Time method specified in Bechtel Topical Report BN-TOP-1, Revision 1.

e. Performance of Type C leak rate testing of the hydrogen and oxygen monitor isolation valves is not required; and

(continued)

5.5.12 Primary Containment Leakage Rate Testing Program (continued)

f. Performance of Type C leak rate testing of the main steam isolation valves at a pressure less than P_a instead of leak rate testing at P_a as specified in ANSI/ANS 56.8-~~1994~~2002.

The peak calculated primary containment internal pressure for the design basis loss of coolant accident, P_a, is 49 psig.

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

Leakage rate acceptance criteria are:

a. Primary containment leakage rate acceptance criterion is $\leq 1.0\ L_a$. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are $< 0.60\ L_a$ for Type B and C tests and $\leq 0.75\ L_a$ for Type A tests.

b. Air lock testing acceptance criteria are:

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

2) For each air lock door, leakage rate is ≤ 5 scfh when the gap between the door seals is pressurized to ≥ 10 psig.

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

5.5.13 Control Room Envelope Habitability Program

A Control Room Envelope (CRE) Habitability Program shall be established and implemented to ensure that CRE habitability is maintained such that, with an OPERABLE Control Room Emergency Ventilation (CREV) System, CRE occupants can control the reactor safely under normal conditions and maintain it in a safe condition following a radiological event, hazardous chemical release, or a smoke challenge. The program shall ensure that adequate radiation protection is provided to permit occupancy of the CRE under design basis accident (DBA) conditions without personnel receiving radiation exposures in excess of 5 rem TEDE for the duration of the accident. The program shall include the following elements:

(continued)

Proposed Technical Specification Changes (Mark-Up) Unit 2

5.5.11 Safety Function Determination Program (SFDP) (continued)

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

5.5.12 Primary Containment Leakage Rate Testing Program

A primary containment leakage rate testing program shall establish requirements to implement the leakage rate testing of the primary containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B as modified by approved exemptions. This program shall be in accordance with the guidelines contained in ~~Regulatory Guide 1.163, September 1995,~~ 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, as modified by the following exceptions:

a. The visual examination of concrete surfaces intended to fulfill the requirements of 10 CFR 50, Appendix J, Option B testing, will be performed in accordance with the requirements of and frequency specified by the ASME Section XI Code, Subsection IWL, except where relief has been authorized by the NRC.

b. The visual examination of the metallic shell, penetrations, and appurtenances intended to fulfill the requirements of 10 CFR 50, Appendix J, Option B, will be performed in accordance with the requirements of and frequency specified by the ASME Section XI Code, Subsection IWE, except where relief has been authorized by the NRC.

c. Following air lock door seal replacement, performance of door seal leakage rate testing with the gap between the door seals pressurized to 10 psig instead of air lock testing at P_a as specified in Nuclear Energy Institute Guideline 94-01, Revision ~~0~~3-A;

d. Reduced duration Type A tests may be performed using the criteria and Total Time method specified in Bechtel Topical Report BN-TOP-1, Revision 1.

e. Performance of Type C leak rate testing of the hydrogen and oxygen monitor isolation valves is not required; and

(continued)

5.5.12 Primary Containment Leakage Rate Testing Program (continued)

f. Performance of Type C leak rate testing of the main steam isolation valves at a pressure less than P_a instead of leak rate testing at P_a as specified in ANSI/ANS 56.8-~~1994~~2002.

The peak calculated primary containment internal pressure for the design basis loss of coolant accident, P_a, is 49 psig.

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

Leakage rate acceptance criteria are:

a. Primary containment leakage rate acceptance criterion is $\leq 1.0\ L_a$. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are $< 0.60\ L_a$ for Type B and C tests and $\leq 0.75\ L_a$ for Type A tests.

b. Air lock testing acceptance criteria are:

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

2) For each air lock door, leakage rate is ≤ 5 scfh when the gap between the door seals is pressurized to ≥ 10 psig.

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

5.5.13 Control Room Envelope Habitability Program

A Control Room Envelope (CRE) Habitability Program shall be established and implemented to ensure that CRE habitability is maintained such that, with an OPERABLE Control Room Emergency Ventilation (CREV) System, CRE occupants can control the reactor safely under normal conditions and maintain it in a safe condition following a radiological event, hazardous chemical release, or a smoke challenge. The program shall ensure that adequate radiation protection is provided to permit occupancy of the CRE under design basis accident (DBA) conditions without personnel receiving radiation exposures in excess of 5 rem TEDE for the duration of the accident. The program shall include the following elements:

(continued)

Revised (Typed) Technical Specification Pages Unit 1

5.5.11 Safety Function Determination Program (SFDP) (continued)

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

5.5.12 Primary Containment Leakage Rate Testing Program

A primary containment leakage rate testing program shall establish requirements to implement the leakage rate testing of the primary containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B as modified by approved exemptions. This program shall be in accordance with the guidelines contained in NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J," Revision 3-A, dated July 2012, and the Limitations and Conditions specified in NEI 94-01, Revision 2-A, dated October 2008, as modified by the following exceptions:

a. The visual examination of concrete surfaces intended to fulfill the requirements of 10 CFR 50, Appendix J, Option B testing, will be performed in accordance with the requirements of and frequency specified by the ASME Section XI Code, Subsection IWL, except where relief has been authorized by the NRC.

b. The visual examination of the metallic shell, penetrations, and appurtenances intended to fulfill the requirements of 10 CFR 50, Appendix J, Option B, will be performed in accordance with the requirements of and frequency specified by the ASME Section XI Code, Subsection IWE, except where relief has been authorized by the NRC.

c. Following air lock door seal replacement, performance of door seal leakage rate testing with the gap between the door seals pressurized to 10 psig instead of air lock testing at P_a as specified in Nuclear Energy Institute Guideline 94-01, Revision 3-A;

d. Reduced duration Type A tests may be performed using the criteria and Total Time method specified in Bechtel Topical Report BN-TOP-1, Revision 1.

e. Performance of Type C leak rate testing of the hydrogen and oxygen monitor isolation valves is not required; and

(continued)

5.5.12 Primary Containment Leakage Rate Testing Program (continued)

f. Performance of Type C leak rate testing of the main steam isolation valves at a pressure less than P_a instead of leak rate testing at P_a as specified in ANSI/ANS 56.8-2002.

The peak calculated primary containment internal pressure for the design basis loss of coolant accident, P_a, is 49 psig.

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

Leakage rate acceptance criteria are:

a. Primary containment leakage rate acceptance criterion is $\leq 1.0\ L_a$. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are $< 0.60\ L_a$ for Type B and C tests and $\leq 0.75\ L_a$ for Type A tests.

b. Air lock testing acceptance criteria are:

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

2) For each air lock door, leakage rate is ≤ 5 scfh when the gap between the door seals is pressurized to ≥ 10 psig.

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

5.5.13 Control Room Envelope Habitability Program

A Control Room Envelope (CRE) Habitability Program shall be established and implemented to ensure that CRE habitability is maintained such that, with an OPERABLE Control Room Emergency Ventilation (CREV) System, CRE occupants can control the reactor safely under normal conditions and maintain it in a safe condition following a radiological event, hazardous chemical release, or a smoke challenge. The program shall ensure that adequate radiation protection is provided to permit occupancy of the CRE under design basis accident (DBA) conditions without personnel receiving radiation exposures in excess of 5 rem TEDE for the duration of the accident. The program shall include the following elements:

(continued)

Revised (Typed) Technical Specification Pages Unit 2

5.5.11 Safety Function Determination Program (SFDP) (continued)

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

5.5.12 Primary Containment Leakage Rate Testing Program

A primary containment leakage rate testing program shall establish requirements to implement the leakage rate testing of the primary containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B as modified by approved exemptions. This program shall be in accordance with the guidelines contained in NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J," Revision 3-A, dated July 2012, and the Limitations and Conditions specified in NEI 94-01, Revision 2-A, dated October 2008, as modified by the following exceptions:

a. The visual examination of concrete surfaces intended to fulfill the requirements of 10 CFR 50, Appendix J, Option B testing, will be performed in accordance with the requirements of and frequency specified by the ASME Section XI Code, Subsection IWL, except where relief has been authorized by the NRC.

b. The visual examination of the metallic shell, penetrations, and appurtenances intended to fulfill the requirements of 10 CFR 50, Appendix J, Option B, will be performed in accordance with the requirements of and frequency specified by the ASME Section XI Code, Subsection IWE, except where relief has been authorized by the NRC.

c. Following air lock door seal replacement, performance of door seal leakage rate testing with the gap between the door seals pressurized to 10 psig instead of air lock testing at P_a as specified in Nuclear Energy Institute Guideline 94-01, Revision 3-A;

d. Reduced duration Type A tests may be performed using the criteria and Total Time method specified in Bechtel Topical Report BN-TOP-1, Revision 1.

e. Performance of Type C leak rate testing of the hydrogen and oxygen monitor isolation valves is not required; and

(continued)

5.5.12 Primary Containment Leakage Rate Testing Program (continued)

f. Performance of Type C leak rate testing of the main steam isolation valves at a pressure less than P_a instead of leak rate testing at P_a as specified in ANSI/ANS 56.8-2002.

The peak calculated primary containment internal pressure for the design basis loss of coolant accident, P_a, is 49 psig.

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

Leakage rate acceptance criteria are:

a. Primary containment leakage rate acceptance criterion is $\leq 1.0\ L_a$. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are $< 0.60\ L_a$ for Type B and C tests and $\leq 0.75\ L_a$ for Type A tests.

b. Air lock testing acceptance criteria are:

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

   2) For each air lock door, leakage rate is ≤ 5 scfh when the gap between the door seals is pressurized to ≥ 10 psig.

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

5.5.13 Control Room Envelope Habitability Program

A Control Room Envelope (CRE) Habitability Program shall be established and implemented to ensure that CRE habitability is maintained such that, with an OPERABLE Control Room Emergency Ventilation (CREV) System, CRE occupants can control the reactor safely under normal conditions and maintain it in a safe condition following a radiological event, hazardous chemical release, or a smoke challenge. The program shall ensure that adequate radiation protection is provided to permit occupancy of the CRE under design basis accident (DBA) conditions without personnel receiving radiation exposures in excess of 5 rem TEDE for the duration of the accident. The program shall include the following elements:

(continued)

Proposed Technical Specification Bases Pages (Mark-Up)
Unit 1 (For Information Only)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1.1

Maintaining the primary containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements of the Primary Containment Leakage Rate Testing Program. The primary containment concrete examinations may be performed during either power operation, e.g., performed concurrently with other primary containment inspection-related activities, or during a maintenance or refueling outage. The visual examinations of penetrations on the exterior of the containment and appurtenances may be performed concurrently with other primary containment inspection-related activities, or during a maintenance or refueling outage. The visual examinations of the metallic shell, as well as penetrations on the interior of the containment, are performed during maintenance or refueling outages since this is the only time these areas are fully accessible. The Primary Containment Leakage Rate Testing Program has been established in accordance with 10 CFR 50.54(o) to implement the requirements of 10 CFR Part 50, Appendix J, Option B (Ref. 3). The Primary Containment Leakage Rate Testing Program also conforms with ~~Regulatory Guide 1.163 (Ref. 6) and~~ Nuclear Energy Institute (NEI) 94-01 (Ref. 7) except for the following:

a. BNP may use the criteria and Total Time method specified in Bechtel Topical Report BN-TOP-1 (Ref. 8) for calculating the primary containment leakage during reduced duration Type A testing. This is an exemption from the requirements of 10 CFR 50 Appendix J (Ref. 3) which, in accordance with NEI 94-01 (Ref. 7), requires the methods for calculating primary containment leakage described in ANSI/ANS 56.8-~~1994~~ 2002 (Ref. 9). The basis for this exemption is described in References 10 and 11.

b. Type C testing is not required for the hydrogen and oxygen monitor isolation valves. This is an exemption from the requirements of 10 CFR 50 Appendix J (Ref. 3). The basis for this exemption is described in Reference 12.

Failure to meet air lock leakage limits (SR 3.6.1.2.1) or main steam isolation valve leakage (SR 3.6.1.3.9) does not necessarily result in a failure of this SR. The impact of the failure to meet SR 3.6.1.2.1 must be evaluated against the Type A, B, and C acceptance criteria of the Primary Containment Leakage Rate Testing Program, and failure to meet SR 3.6.1.3.9 must be evaluated against Type A acceptance criteria of the Primary Containment Leakage Rate Testing Program.

As left leakage prior to the first startup after performing required leakage testing is required to be < 0.6 L_a for combined Type B and C leakage, and ≤ 0.75 L_a for overall Type A leakage. At all other times between required

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.1.1 (continued)

leakage rate tests, the acceptance criteria is based on an overall Type A leakage limit of ≤ 1.0 L_a. At ≤ 1.0 L_a the offsite dose consequences are bounded by the assumptions of the safety analysis. The Frequency is required by the Primary Containment Leakage Rate Testing Program.

SR Frequencies are as required by the Containment Leakage Rate Testing Program. These periodic testing requirements verify that the containment leakage rate does not exceed the leakage rate assumed in the safety analysis.

SR 3.6.1.1.2

Maintaining the pressure suppression function of primary containment requires limiting the leakage from the drywell to the suppression chamber. Thus, if an event were to occur that pressurized the drywell, the steam would be directed through the downcomers into the suppression pool. This SR measures drywell to suppression chamber differential pressure during a 10 minute period to ensure that the leakage paths that would bypass the suppression pool (downcomers) are within allowable limits.

Satisfactory performance of this SR can be achieved by establishing a known differential pressure between the drywell and the suppression chamber and verifying that the differential pressure between the suppression chamber and the drywell does not decrease by more than 0.25 inch of water per minute over a 10 minute period. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 6.2.
2. UFSAR, Section 15.6.
3. 10 CFR 50, Appendix J, Option B.
4. NEDC-33039P, Safety Analysis Report for Brunswick Steam Electric Plant Units 1 and 2, Extended Power Uprate, August 2001.
5. 10 CFR 50.36(c)(2)(ii).
6. ~~NRC Regulatory Guide 1.163, Performance-Based Containment Leak-Rate Testing Program, September 1995.~~(Not Used)
7. Nuclear Energy Institute (NEI) 94-01, Industry Guideline for Implementing Performance-Based Option of 10 CFR 50 Appendix J, ~~July 26, 1995~~ Revision 3-A, dated July 2012, and the Limitations and Conditions specified in NEI 94-01, Revision 2-A, dated October 2008.

(continued)

BASES

REFERENCES (continued)

8. Bechtel Topical Report BN-TOP-1, Revision 1, November 1, 1972.

9. ANSI/ANS 56.8-~~1994~~2002.

10. NRC SER; Issuance of Amendment No. 181 to Facility Operating License No. DPR-71 and Amendment No. 213 to Facility Operating License No. DPR-62 Regarding 10 CFR 50 Appendix J, Option B - Brunswick Steam Electric Plant, Units 1 and 2 (BSEP 95-0316) (TAC Nos. M93679 and M93680); dated February 1, 1996.

11. NRC SER, Exemption from the Requirements of Appendix J for Brunswick Steam Electric Plant, Units 1 and 2, dated February 17, 1988.

12. NRC SER, Technical Exemption from the Requirements of Appendix J, dated May 12, 1987.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.1.2.1

Maintaining the primary containment air lock OPERABLE requires compliance with the leakage rate test requirements of the Primary Containment Leakage Rate Testing Program. The Primary Containment Leakage Rate Testing Program has been established in accordance with 10 CFR 50.54(o) to implement the requirements of 10 CFR Part 50, Appendix J, Option B (Ref. 4), and conforms with ~~Regulatory Guide 1.163 (Ref. 5) and~~ Nuclear Energy Institute (NEI) 94-01 (Ref. 6) except for the following:

a. The local leak rate testing requirements of the primary containment air lock doors may be modified to perform the tests at a pressure less than P_a following replacement of the air lock door seals. This is an exception from the requirements of NEI 94-01 (Ref. 6). The basis for this exception is described in Reference 7.

This SR reflects the leakage rate testing requirements with respect to air lock leakage (Type B leakage tests). The acceptance criteria were established as a small fraction of the total allowable primary containment leakage. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall primary containment leakage rate. The Frequency is required by the Primary Containment Leakage Rate Testing Program.

The SR has been modified by two Notes. Note 1 states that an inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. This is considered reasonable since either air lock door is capable of providing a fission product barrier in the event of a DBA. Note 2 has been added to this SR, requiring results to be evaluated against the acceptance criteria which are applicable to SR 3.6.1.1.1. This ensures that air lock leakage is properly accounted for in determining the combined Type B and C primary containment leakage rate.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.2.2

The air lock interlock mechanism is designed to prevent simultaneous opening of both doors in the air lock. Since both the inner and outer doors of the air lock are designed to withstand the maximum expected post accident primary containment pressure, closure of either door will support primary containment OPERABILITY. Thus, the interlock feature supports primary containment OPERABILITY while the air lock is being used for personnel transit in and out of the containment. Periodic testing of this interlock demonstrates that the interlock will function as designed and that simultaneous inner and outer door opening will not inadvertently occur. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 3.8.2.4.3.2.
2. NEDC-33039P, Safety Analysis Report for Brunswick Units 1 and 2 Extended Power Uprate, August 2001.
3. 10 CFR 50.36(c)(2)(ii).
4. 10 CFR 50, Appendix J, Option B.
5. ~~NRC Regulatory Guide 1.163, Performance-Based Containment Leak-Rate Testing Program, September 1995.~~(Not Used)
6. Nuclear Energy Institute (NEI) 94-01, Industry Guideline for Implementing Performance-Based Option of 10 CFR 50 Appendix J, ~~July 26, 1995~~ Revision 3-A, dated July 2012, and the Limitations and Conditions specified in NEI 94-01, Revision 2-A, dated October 2008.
7. NRC SER, Brunswick 1 & 2 - Amendments No. 10 and 36 to Operating Licenses Revising Technical Specifications to Grant Exemptions from Specific Requirements of 10 CFR 50 Appendix J, dated November 8, 1977.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.8

The TIP shear isolation valves are actuated by explosive charges. An in place functional test is not possible with this design. The explosive squib is removed and tested to provide assurance that the valves will actuate when required. The replacement charge for the explosive squib shall be from the same manufactured batch as the one fired or from another batch that has been certified by having one of the batch successfully fired. The Frequency of this SR is in accordance with the requirements of the INSERVICE TESTING PROGRAM.

SR 3.6.1.3.9

The analyses in References 2, 6, 7, and 8 are based on leakage that is less than the specified leakage rate. Leakage through each main steam line must be ≤ 100 scfh when tested at ≥ P_t (25 psig). The combined leakage rate for all four mains steam lines must be ≤ 150 scfh when tested at ≥ 25 psig in accordance with the Primary Containment Leakage Rate Testing Program. The Primary Containment Leakage Rate Testing Program has been established in accordance with 10 CFR 50.54(o) to implement the requirements of 10 CFR Part 50, Appendix J, Option B (Ref. 9), and conforms with ~~Regulatory Guide 1.163 (Ref. 10) and~~ Nuclear Energy Institute (NEI) 94-01 (Ref. 11) except for the following:

a. Local leak rate testing of the MSIVs may be performed at a pressure less than P_a. This is an exemption from the requirements of 10 CFR 50 Appendix J (Ref. 9). The basis for this exemption is described in Reference 12.

The Frequency is required by the Primary Containment Leakage Rate Testing Program.

(continued)

BASES

REFERENCES

1. UFSAR, Chapter 15.
2. NEDC-32466P, Power Uprate Safety Analysis Report for Brunswick Steam Electric Plant Units 1 and 2, September 1995.
3. 10 CFR 50.36(c)(2)(ii).
4. Technical Requirements Manual.
5. NEDO-32977-A, "Excess Flow Check Valve Testing Relaxation," June 2000.
6. UFSAR, Section 15.2.3.
7. NRC letter, Brunswick Steam Electric Plant, Units 1 and 2 - Issuance of Amendment Re: Alternative Source Term, May 30, 2002.
8. BNP Calculation No. BNP-RAD-007, Rev. 1B, DBA-LOCA Radiological Dose With Alternate Source Term.
9. 10 CFR 50, Appendix J, Option B.
10. ~~NRC Regulatory Guide 1.163, Performance-Based Containment Leak-Rate Testing Program, September 1995.~~(Not Used)
11. Nuclear Energy Institute (NEI) 94-01, Industry Guideline for Implementing Performance-Based Option of 10 CFR 50 Appendix J,~~ July 26, 1995~~ Revision 3-A, dated July 2012, and the Limitations and Conditions specified in NEI 94-01, Revision 2-A, dated October 2008.
12. NRC SER, Brunswick 1 & 2 - Amendments No. 10 and 36 to Operating Licenses Revising Technical Specifications to Grant Exemptions from Specific Requirements of 10 CFR 50 Appendix J, dated November 8, 1977.

BSEP Evaluation of Risk Significance of Permanent ILRT Evaluation

JENSEN HUGHES

Advancing the Science of Safety

Brunswick Steam Electric Plant:
Evaluation of Risk Significance of Permanent ILRT Extension

54011-CALC-01

Prepared for:

Duke Energy Nuclear

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Revision: 0

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Preparer: Kelly Wright	Kelly Wright 2018.12.14 09:18:14-05'00'
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REVISION RECORD SUMMARY

Revision	Revision Summary
0	Initial issue

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1.0 PURPOSE

The purpose of this analysis is to provide a risk assessment of permanently extending the currently allowed containment Type A Integrated Leak Rate Test (ILRT) interval from ten years to fifteen years. The extension would allow for substantial cost savings as the ILRT could be deferred for additional scheduled refueling outages for Brunswick Steam Electric Plant (BSEP) Units 1 and 2. The risk assessment follows the guidelines from NEI 94-01, Revision 3-A [Reference 1], the methodology used in EPRI 1009325 [Reference 24], the NEI "Interim Guidance for Performing Risk Impact Assessments in Support of One-Time Extensions for Containment Integrated Leakage Rate Test Surveillance Intervals" from November 2001 [Reference 3], the NRC regulatory guidance on the use of Probabilistic Risk Assessment (PRA) as stated in Regulatory Guide 1.200 [Reference 43] as applied to ILRT interval extensions, risk insights in support of a request for a plant's licensing basis as outlined in Regulatory Guide (RG) 1.174 [Reference 4], the methodology used for Calvert Cliffs to estimate the likelihood and risk implications of corrosion-induced leakage of steel liners going undetected during the extended test interval [Reference 5], and the methodology used in EPRI 1018243, Revision 2-A of EPRI 1009325 [Reference 24].

2.0 SCOPE

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

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

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

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

use in evaluating the impact of the proposed ILRT changes.

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

The acceptance guidelines in RG 1.174 are used to assess the acceptability of this permanent extension of the Type A test interval beyond that established during the Option B rulemaking of Appendix J. RG 1.174 defines very small changes in the risk-acceptance guidelines as increases in Core Damage Frequency (CDF) less than 10^{-6} per reactor year and increases in Large Early Release Frequency (LERF) less than 10^{-7} per reactor year. Since containment accident pressure is credited in support of ECCS performance to mitigate design basis accidents at BSEP, the ILRT extension may impact CDF. A detailed analysis is performed and described in Section 5.2.7; this shows the ILRT extension has only a very small effect on CDF. Therefore, the more relevant risk-impact metric is LERF. RG 1.174 also defines small changes in LERF as below 10^{-6} per reactor year. RG 1.174 discusses defense-in-depth and encourages the use of risk analysis techniques to help ensure and show that key principles, such as the defense-in-depth philosophy, are met. Therefore, the increase in the Conditional Containment Failure Probability (CCFP), which helps ensure the defense-in-depth philosophy is maintained, is also calculated.

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

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

3.0 REFERENCES

The following references were used in this calculation:

1. *Revision 3-A to Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J*, NEI 94-01, July 2012.
2. *Risk Impact Assessment of Revised Containment Leak Rate Testing Intervals*, EPRI, Palo Alto, CA, EPRI TR-104285, August 1994.
3. *Interim Guidance for Performing Risk Impact Assessments in Support of One-Time Extensions for Containment Integrated Leakage Rate Test Surveillance Intervals*, Revision 4, developed for NEI by EPRI and Data Systems and Solutions, November 2001.
4. An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis, Regulatory Guide 1.174, Revision 3, January 2018.
5. *Response to Request for Additional Information Concerning the License Amendment Request for a One-Time Integrated Leakage Rate Test Extension*, Letter from Mr. C. H. Cruse (Calvert Cliffs Nuclear Power Plant) to NRC Document Control Desk, Docket No. 50-317, March 27, 2002.
6. Performance-Based Containment Leak-Test Program, NUREG-1493, September 1995.
7. *Evaluation of Severe Accident Risks: Peach Bottom Unit 2*, Main Report NUREG/CR-4551, SAND86-1309, Volume 4, Revision 1, Part 1, October 1990.
8. Letter from R. J. Barrett (Entergy) to U. S. Nuclear Regulatory Commission, IPN-01-007, January 18, 2001.
9. United States Nuclear Regulatory Commission, Indian Point Nuclear Generating Unit No. 3 – Issuance of Amendment Re: Frequency of Performance-Based Leakage Rate Testing (TAC No. MB0178), April 17, 2001.
10. *Impact of Containment Building Leakage on LWR Accident Risk*, Oak Ridge National Laboratory, NUREG/CR-3539, ORNL/TM-8964, April 1984.
11. *Reliability Analysis of Containment Isolation Systems*, Pacific Northwest Laboratory, NUREG/CR-4220, PNL-5432, June 1985.
12. Technical Findings and Regulatory Analysis for Generic Safety Issue II.E.4.3 'Containment Integrity Check', NUREG-1273, April 1988.
13. *Review of Light Water Reactor Regulatory Requirements*, Pacific Northwest Laboratory, NUREG/CR-4330, PNL-5809, Volume 2, June 1986.
14. Shutdown Risk Impact Assessment for Extended Containment Leakage Testing Intervals Utilizing ORAM™, EPRI, Palo Alto, CA, TR-105189, Final Report, May 1995.
15. *Severe Accident Risks: An Assessment for Five U. S. Nuclear Power Plants*, NUREG-1150, December 1990.
16. United States Nuclear Regulatory Commission, Reactor Safety Study, WASH-1400, October 1975.
17. Calculation BNP-PSA-102, Revision 0, Brunswick Nuclear Plant, "Brunswick PRA Working Model."
18. Calculation BNP-PSA-049, Revision 4, Brunswick Nuclear Plant, "PRA Model Sections 7-9 Level 2 Analysis."
19. Brunswick Steam Electric Plant, License Renewal Application, Appendix F – Severe Accident Mitigation Alternatives, Environmental Report, 2005.

20. Anthony R. Pietrangelo, One-time extensions of containment integrated leak rate test interval – additional information, NEI letter to Administrative Points of Contact, November 30, 2001.
21. Letter from J. A. Hutton (Exelon, Peach Bottom) to U. S. Nuclear Regulatory Commission, Docket No. 50-278, License No. DPR-56, LAR-01-00430, dated May 30, 2001.
22. *Risk Assessment for Joseph M. Farley Nuclear Plant Regarding ILRT (Type A) Extension Request*, prepared for Southern Nuclear Operating Co. by ERIN Engineering and Research, P0293010002-1929-030602, March 2002.
23. Letter from D. E. Young (Florida Power, Crystal River) to U. S. Nuclear Regulatory Commission, 3F0401-11, dated April 25, 2001.
24. *Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals*, Revision 2-A of 1009325, EPRI, Palo Alto, CA, 1018243, October 2008.
25. Preliminary Notification of Event or Unusual Occurrence PNO-1-06-012, Evaluation of Oyster Creek Containment Design Function, ML063130424, November 9, 2006.
26. Calculation BNP-PSA-001, Revision 11, Brunswick Nuclear Plant, “Brunswick Risk and Insights Calculation.”
27. Updated FSAR for Brunswick Steam Electric Plant, Units 1 and 2, Revision 25.
28. Letter L-14-121, ML14111A291, FENOC Evaluation of the Proposed Amendment, Beaver Valley Power Station, Unit Nos. 1 and 2, April 2014.
29. Technical Letter Report ML112070867, Containment Liner Corrosion Operating Experience Summary, Revision 1, August 2011.
30. License Amendment Request to Adopt NFPA 805 Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants, January 28, 2015, ML14310A808.
31. Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Vulnerabilities, NUREG-1407, June 1991.
32. Calculation BNP-PSA-080, Revision 5, Brunswick Nuclear Plant, “BNP Fire PRA – Quantification.”
33. “ML14083A586, EPRI Evaluation, “Fleet Seismic Core Damage Frequency Estimates for Central and Eastern U.S. Nuclear Power Plants Using New Site-Specific Seismic Hazard Estimates,” March 11, 2014.
34. Generic Issue 199 (GI-199), ML100270582, September 2010, “Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern United States on Existing Plants: Safety/Risk Assessment.”
35. “The Nuclear Energy Institute - Seismic Risk Evaluations for Plants in the Central and Eastern United States,” ML14083A596, March 2014.
36. Calculation BNP-PSA-068, “BNP – PSA Model Peer Review F&O Resolution,” Revision 7.
37. Brunswick Nuclear Plant, Unit 1, Reactor Containment Building Integrated Leak Rate Test Report, ILRT-R-100411, April 2010.
38. Brunswick Nuclear Plant, Unit 2, Reactor Containment Building Integrated Leak Rate Test Report, BRU2ILRT.15-R150408A, April 2015.
39. Calculation BNP-PSA-076, Revision 0, Brunswick Nuclear Plant, “BNP Fire PRA Success Criteria MAAP Analysis.”

40. Calculation 0E11-0028, Brunswick Nuclear Plant, “Determination of RHR and Core Spray NPSH Margins After Power Uprate.”
41. ASME/ANS RA-Sa-2009, Addenda to ASME/ANS RA-S-2008: Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications.
42. Calculation BNP-PSA-047, Revision 4, Brunswick Nuclear Plant, “PRA Model Appendix L MAAP Deck and Supporting Documentation.”
43. Regulatory Guide 1.200, *An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities*, Revision 2, March 2009.
44. NEI 07-12, *Fire Probabilistic Risk Assessment (FPRA) Peer Review Process Guidelines*, Revision 1.
45. NEI 05-04, *Process for Performing Internal Events PRA Peer Reviews Using the ASME/ANS PRA Standard*, Revision 2.
46. Calculation BNP-PSA-048, Revision 2, Brunswick Nuclear Plant, “PRA Model Appendix K PDS MAAP Analysis.”
47. Individual Plant Examination for External Events Submittal, Brunswick Nuclear Plant, June 1995.
48. Airport Facilities Data, Federal Aviation Administration, 07-02-2018. https://www.faa.gov/airports/airport_safety/airportdata_5010/menu/
49. NUREG/CR-2973, “Loss of DHR Sequences at Browns Ferry Unit One – Accident Sequence Analysis,” Oak Ridge Nation Laboratory, May 1983.
50. Calculation BNP-PSA-094, Revision 2, Brunswick Nuclear Plant, “PSA Model External Flooding Analysis.”
51. Calculation 54011-CALC-02, JENSEN HUGHES, “Brunswick Steam Electric Plant: Detailed Loss of CAP Analysis,” Revision 0.

4.0 ASSUMPTIONS AND LIMITATIONS

The following assumptions were used in the calculation:

- The acceptability (i.e., technical adequacy) of the BSEP PRA is either consistent with the requirements of Regulatory Guide 1.200 or where gaps exist, the gaps have been addressed, as is relevant to this ILRT interval extension, as detailed in Appendix A.
- The BSEP Level 1 and Level 2 internal events PRA models provide representative results.
- It is appropriate to use the BSEP internal events PRA model to effectively describe the risk change attributable to the ILRT extension. An analysis is performed in Section 5.2.8 to show the effect of including external event models for the ILRT extension. The Seismic risk from GI-199 [Reference 34] and Fire PRA model Revision 5 [Reference 32] are used for this analysis.
- Dose results for the containment failures modeled in the PSA can be characterized by information provided in NUREG/CR-4551 [Reference 7]. They are estimated by scaling the NUREG/CR-4551 results by population differences for Brunswick compared to the NUREG/CR-4551 reference plant. The representative containment leakage for Class 1 sequences is $1L_a$. Class 3 accounts for increased leakage due to Type A inspection failures.
- The lowest consequence calculations (i.e., intact containment and small leakages) are based on scaling the NUREG/CR-4551 [Reference 7] results for such cases using population differences, and also based on differences in the allowable Technical Specification Leakage. Class 7 releases are based on values provided in Reference 19.
- The representative containment leakage for Class 3a sequences is $10L_a$ based on the previously approved methodology performed for Indian Point Unit 3 [Reference 8, Reference 9].
- The representative containment leakage for Class 3b sequences is $100L_a$ based on the guidance provided in EPRI Report No. 1009325, Revision 2-A (EPRI 1018243) [Reference 24].
- The Class 3b can be very conservatively categorized as LERF based on the previously approved methodology [Reference 8, Reference 9].
- The impact on population doses from containment bypass scenarios is not altered by the proposed ILRT extension, but is accounted for in the EPRI methodology as a separate entry for comparison purposes. Since the containment bypass contribution to population dose is fixed, no changes in the conclusions from this analysis will result from this separate categorization.
- The reduction in ILRT frequency does not impact the reliability of containment isolation valves to close in response to a containment isolation signal.
- While precise numbers are maintained throughout the calculations, some values have been rounded when presented in this report. Therefore, rounding differences may result in table summations.

5.0 METHODOLOGY AND ANALYSIS

5.1 Inputs

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

5.1.1 General Resources Available

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

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

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

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

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

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

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

calculate the unavailability of containment due to leakage.

NUREG-1273 [Reference 12]

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

NUREG/CR-4330 [Reference 13]

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

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

EPRI TR-105189 [Reference 14]

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

NUREG-1493 [Reference 6]

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

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

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

EPRI TR-104285 [Reference 2]

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

5.1.2 Plant Specific Inputs

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

- Level 1 Model results [Reference 17, Reference 26]
- Level 2 Model results [Reference 17, Reference 18, Reference 26]
- Population Dose calculations by release category [Reference 19, Reference 7]
- ILRT results to demonstrate adequacy of the administrative and hardware issues [References 37 and 38]

<u>BSEP Model</u>

The Internal Events PRA Model that is used for BSEP is characteristic of the as-built plant. The current Level 1 model (MOR16) [Reference 17] is a linked fault tree model. The Unit 1 CDF is 5.00E-06/year and the Unit 2 CDF is 4.67E-06 (including internal flooding) [Reference 17]. The Unit 1 LERF is 1.78E-07/year and the Unit 2 LERF is 1.74E-07 (including internal flooding) [Reference 17]. Table 5-1 and Table 5-2 provide a summary of the Unit 1 and Unit 2 Internal Events CDF by sequence type. Percent contributions by sequence type are provided in Reference 20.

The total Fire CDF is 2.09E-05/year for Unit 1 and 2.45E-05/year for Unit 2; the total Fire LERF is 4.58E-06/year for Unit 1 and 4.53E-06/year for Unit 2 [Reference 17]. The total High Winds CDF is 1.98E-06/year for Unit 1 and 1.81E-06/year for Unit 2; the total High Winds LERF is 4.69E-08/year for Unit 1 and 4.40E-08/year for Unit 2 [Reference 17]. The seismic risk is taken from GI-199 [Reference 34]. Refer to Section 5.2.8 for further details on external events as they pertain to this analysis.

Table 5-1 – Unit 1 Internal Events CDF by Sequence Type

Internal Events	Frequency (per year)
Transients	4.69E-06
ATWS	2.55E-07
LOCAs	4.00E-08
SBO	2.50E-08
Total Unit 1 Internal Events CDF	5.00E-06

Table 5-2 – Unit 2 Internal Events CDF by Sequence Type

Internal Events	Frequency (per year)
Transients	4.33E-06
ATWS	2.43E-07
SBO	6.07E-08
LOCAs	3.74E-08
Total Unit 2 Internal Events CDF	4.67E-06

Release Category Definitions

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

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

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

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

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

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

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

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

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

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

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

5.2 Analysis

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

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

Core damage sequences in which the containment remains intact initially and in the long term (EPRI 1009325, Class 1 sequences [Reference 24]).

Core damage sequences in which containment integrity is impaired due to random isolation failures of plant components other than those associated with Type B or Type C test components. For example, liner breach or bellow leakage (EPRI 1009325, Class 3 sequences [Reference 24]).

Accident sequences involving containment bypassed (EPRI 1009325, Class 8 sequences [Reference 24]), large containment isolation failures (EPRI 1009325, Class 2 sequences [Reference 24]), and small containment isolation "failure-to-seal" events (EPRI 1009325, Class 4 and 5 sequences [Reference 24]) are accounted for in this evaluation as part of the baseline risk profile. However, they are not affected by the ILRT frequency change.

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

Table 5-4 – EPRI Accident Class Definitions

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

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

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

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

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

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

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

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

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

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

The frequencies for the severe accident classes defined in Table 5-4 were developed for BSEP by first determining the frequencies for Classes 1, 2, 7, and 8. Table 5-5 presents the grouping of the release categories in EPRI Classes. Table 5-6 provides a summary of the accident sequence frequencies that can lead to radionuclide release to the public and have been derived consistent with the definitions of accident classes defined in EPRI TR-104285 [Reference 2], the NEI Interim Guidance [Reference 3], and guidance provided in EPRI Report No. 1009325, Revision 2-A [Reference 24]. Adjustments were made to the Class 3b and hence Class 1

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

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

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

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

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

$$Freq_{U1class3a} = P_{class3a} * (CDF_{U1} - LERF_{U1}) = \frac{2}{217} * (5.00\text{E-}06 - 1.78\text{E-}07) = 4.44\text{E-}08$$

$$Freq_{U2class3a} = P_{class3a} * (CDF_{U2} - LERF_{U2}) = \frac{2}{217} * (4.67\text{E-}06 - 1.74\text{E-}07) = 4.14\text{E-}08$$

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

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

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

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

$$Freq_{U1class3b} = P_{class3b} * (CDF_{U1} - LERF_{U1}) = \frac{.5}{218} * (5.00\text{E-}06 - 1.78\text{E-}07) = 1.11\text{E-}08$$

$$Freq_{U2class3b} = P_{class3b} * (CDF_{U2} - LERF_{U2}) = \frac{.5}{218} * (4.67\text{E-}06 - 1.74\text{E-}07) = 1.03\text{E-}08$$

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

Class 1 Sequences. This group consists of all core damage accident progression bins for which the containment remains intact (modeled as Technical Specification Leakage). The Intact frequency was determined in Reference 19 but cannot be applied directly to the current PRA model. In order to determine the Intact frequency for this analysis, the ratio of the Intact to total release category frequency was calculated from Reference 19 (43.2%) and applied to the total Unit 1 and Unit 2 CDF. The Class 1 frequency per year is initially determined from the EPRI

Accident Class 1 (Intact) frequency listed in Table 5-5 and then subtracting the EPRI Class 3a and 3b frequency (to preserve total CDF), calculated below:

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

Class 2 Sequences. This group consists of core damage accident progression bins with large containment isolation failures. This is calculated by summing the Fussell-Vesely (FV) of LERF sequence flags related to containment isolation failure (X-3A-43, X-3C-43, X-IA1-43, X-IBE1-43, and X-ID1-43) and multiplying the total FV by the LERF. The FV values were taken from the importance measures for the Internal Events and Internal Flooding LERF cutsets. The sum of the FVs for Unit 1 is 3.35E-01 and 2.78E-01 for Unit 2. The frequency per year for these sequences is obtained from the EPRI Accident Class 2 frequency listed in Table 5-6.

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

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

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

Class 7 Sequences. This group consists of all core damage accident progression bins in which containment failure is induced by severe accident phenomena (e.g., overpressure). This frequency is calculated by subtracting the Class 1, 2, and 8 frequencies from the total CDF. For this analysis, the frequency is determined from the EPRI Accident Class 7 frequency listed in Table 5-6.

Class 8 Sequences. This group consists of risk from core damage accident class 5 (containment bypass). This is calculated by multiplying the FV of the containment bypass LERF sequence flag (CNT1CNT-CO-BYPSS or CNT2CNT-CO-BYPSS) by the total LERF. The FV for the Unit 1 sequence flag is 2.55E-03 and 2.73E-03 for the Unit 2 sequence flag. For this analysis, the total frequency is listed in Table 5-6.

Table 5-5 – Release Category Frequencies

Containment End State	EPRI Category	Unit 1 Frequency (/yr)	Unit 2 Frequency (/yr)
Intact Containment	1	2.16E-06	2.02E-06
Large Isolation Failure	2	5.98E-08	4.85E-08
Failures Induced by Phenomena	7	2.78E-06	2.60E-06
ISLOCA-Bypass	8	4.55E-10	4.76E-10

Table 5-6 – Baseline Risk Profile

Class	Description	Unit 1 Frequency (/yr)	Unit 2 Frequency (/yr)
1	No containment failure	2.10E-06[2]	1.97E-06[2]
2	Large containment isolation failures	5.98E-08	4.85E-08
3a	Small isolation failures (liner breach)	4.44E-08	4.14E-08
3b	Large isolation failures (liner breach)	1.11E-08	1.03E-08
4	Small isolation failures - failure to seal (type B)	ε[1]	ε[1]
5	Small isolation failures - failure to seal (type C)	ε[1]	ε[1]
6	Containment isolation failures (dependent failure, personnel errors)	ε[1]	ε[1]
7	Severe accident phenomena induced failure (early and late)	2.78E-06	2.60E-06
8	Containment bypass	4.55E-10	4.76E-10
	Total	5.00E-06	4.67E-06

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

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

Plant-specific release analyses were performed to estimate the person-rem doses to the population within a 50-mile radius from the plant. The yearly population dose is provided in Table F-12 of Reference 19 and the frequency for each release category based on release size and timing (e.g., large early, small late, etc.) is provided in Table F-4 of Reference 19. From this data, the population dose (person-rem) for each release category was calculated by dividing the yearly population dose by the total release category frequency (except for release category H/E, as discussed below). For instance, the yearly population dose for the high-intermediate (H/I) release category is 9.13 person-rem/yr and the total frequency is 3.79E-06/yr, which leads to a dose of 2.41E+06 person-rem. The Class 7 dose is the summation of the dose for each release category totaling 8.49E+06 person-rem.

The only exception is for release category H/E (large early release) as the total frequency provided in Table F-4 of Reference 19 was not used because BSEP Class V pertains to EPRI Class 8, and thus, the Class V frequency was subtracted from the total H/E frequency, and this adjusted frequency (1.83E-06/yr) along with the dose rate in Table F-12 of Reference 19 is used to calculate the dose. As discussed in Section 5.2.1, five sequences associated with BSEP Classes IA, IBE, ID, IIIA, and IIIC are used to determine the EPRI Class 2 frequency, and realistically the contribution of these sequences to the H/E frequency should be determined and then removed from the total H/E frequency; however, the frequency associated with these sequences is included in the H/E frequency. This is conservative for the analysis as this leads to a higher H/E frequency and a lower EPRI Class 7 dose, which leads to a lower baseline total dose, and thus, a higher percent change in dose rate for the ILRT extension.

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

$$\mathrm{AF_{power}} = \mathrm{PLB} \,/\, \mathrm{PLP} = 2923 \,/\, 3293 = 0.888$$

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

$\mathrm{AF_{leakage}} = \mathrm{LRB} / \mathrm{LRP}$

Since the leakage rates are in terms of the containment volume, the ratio of containment volumes is needed to relate the leakage rates. The TS maximum allowed containment leakage at BSEP (TS_B) is 0.5%/day [Reference 27]; the containment free volume at BSEP (VOL_B) is 164,000 ft^3 [Reference 27]. The TS maximum allowed containment leakage at Peach Bottom Unit 2 (TS_{PB}) is 0.5%/day [Reference 7]; the containment free volume at Peach Bottom Unit 2 (VOL_{PB}) is 307,000 ft^3 [Reference 7]. Therefore,

$\mathrm{LRB} = \mathrm{TS_B} * \mathrm{VOL_B}$

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

$\mathrm{AF_{leakage}} = (0.5 * 164000) / (0.5 * 307000) = 0.534$

The adjustment factor for population ($AF_{Population}$) is defined as the ratio of the population within 50-mile radius of BSEP (POPB) [Reference 19] to that of Peach Bottom Unit 2 (POPP) [Reference 7]. The 2036 population surrounding BSEP was conservatively estimated as 847,834 [Reference 19]. This adjustment factor is calculated as follows:

$\mathrm{AF_{Population}} = \mathrm{POPB} / \mathrm{POPP} = 847834 / 3020000 = 0.281$

Consequences dependent on the INTACT TS Leakage (collapsed accident progression bins 8 and 10).

$\mathrm{AF_{INTACT}} = \mathrm{AF_{power}} * \mathrm{AF_{Leakage}} * \mathrm{AF_{Population}} = 0.888 * 0.534 * 0.281 = 0.133$

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

$\mathrm{AF} = \mathrm{AF_{power}} * \mathrm{AF_{Population}} = 0.888 * 0.281 = 0.249$

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

$\mathrm{BPD_{Class1}} = \mathrm{AF_{INTACT}} * \mathrm{PD_{CAPB8}} + \mathrm{AF_{INTACT}} * \mathrm{PD_{CAPB10}} = 0.133 * 4.94\mathrm{E}{+}3 + 0.133 * 0 = 6.58\mathrm{E}{+}2$

$\mathrm{BPD_{Class2}} = \mathrm{AF} * \mathrm{PD_{CAPB3}} = 0.249 * 2.97\mathrm{E}{+}6 = 7.40\mathrm{E}{+}5$

$\mathrm{BPD_{Class8}} = \mathrm{AF} * \mathrm{PD_{CAPB7}} = 0.249 * 1.95\mathrm{E}{+}6 = 4.86\mathrm{E}{+}5$

Table 5-7 provides a correlation of BSEP population dose to EPRI Accident Class. Table 5-8 presents dose exposures calculated from the methodology described in Reference 24 and data from Reference 19. Table 5-9 and Table 5-10 present the baseline risk profiles for Units 1 and 2, respectively.

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

$EPRI\ Class\ 3a\ Population\ Dose = 10 * 6.58E{+}2 = 6.58E{+}3$

$$EPRI\ Class\ 3b\ Population\ Dose = 100 * 6.58E{+}2 = 6.58E{+}4$$

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

EPRI Category	Unit 1 Frequency (/yr)	Unit 2 Frequency (/yr)	Dose (person-rem)
Class 1	2.16E-06	2.02E-06	6.58E+02
Class 2	5.98E-08	4.85E-08	7.40E+05
Class 6	N/A – Included in Class 2		
Class 7	2.78E-06	2.60E-06	8.49E+06
Class 8	4.55E-10	4.76E-10	4.86E+05

Table 5-8 – Baseline Population Doses

Class	Description	Population Dose (person-rem)
1	No containment failure	6.58E+02
2	Large containment isolation failures	7.40E+05
3a	Small isolation failures (liner breach)	6.58E+03[1]
3b	Large isolation failures (liner breach)	6.58E+04[2]
4	Small isolation failures - failure to seal (type B)	N/A
5	Small isolation failures - failure to seal (type C)	N/A
6	Containment isolation failures (dependent failure, personnel errors)	N/A
7	Severe accident phenomena induced failure (early and late)	8.49E+06
8	Containment bypass	4.86E+05

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

The baseline risk profile is presented in Table 5-9 for Unit 1 and Table 5-10 for Unit 2.

Table 5-9 – Unit 1 Baseline Risk Profile for ILRT

Class	Description	Frequency (/yr)	Contribution (%)	Population Dose (person-rem)	Population Dose Rate (person-rem/yr)
1	No containment failure[2]	2.10E-06	42.08%	6.58E+02	1.38E-03
2	Large containment isolation failures	5.98E-08	1.20%	7.40E+05	4.42E-02
3a	Small isolation failures (liner breach)	4.44E-08	0.89%	6.58E+03	2.92E-04
3b	Large isolation failures (liner breach)	1.11E-08	0.22%	6.58E+04	7.27E-04
4	Small isolation failures - failure to seal (type B)	ε[1]	ε[1]	ε[1]	ε[1]
5	Small isolation failures - failure to seal (type C)	ε[1]	ε[1]	ε[1]	ε[1]
6	Containment isolation failures (dependent failure, personnel errors)	ε[1]	ε[1]	ε[1]	ε[1]
7	Severe accident phenomena induced failure (early and late)	2.78E-06	55.60%	8.49E+06	2.36E+01
8	Containment bypass	4.55E-10	0.01%	4.86E+05	2.21E-04
	Total	**5.00E-06**			**2.37E+01**

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

Table 5-10 – Unit 2 Baseline Risk Profile for ILRT

Class	Description	Frequency (/yr)	Contribution (%)	Population Dose (person-rem)	Population Dose Rate (person-rem/yr)
1	No containment failure[2]	1.97E-06	42.08%	6.58E+02	1.29E-03
2	Large containment isolation failures	4.85E-08	1.04%	7.40E+05	3.59E-02
3a	Small isolation failures (liner breach)	4.14E-08	0.89%	6.58E+03	2.72E-04
3b	Large isolation failures (liner breach)	1.03E-08	0.22%	6.58E+04	6.78E-04
4	Small isolation failures - failure to seal (type B)	ε[1]	ε[1]	ε[1]	ε[1]
5	Small isolation failures - failure to seal (type C)	ε[1]	ε[1]	ε[1]	ε[1]
6	Containment isolation failures (dependent failure, personnel errors)	ε[1]	ε[1]	ε[1]	ε[1]
7	Severe accident phenomena induced failure (early and late)	2.60E-06	55.76%	8.49E+06	2.21E+01
8	Containment bypass	4.76E-10	0.01%	4.86E+05	2.31E-04
	Total	**4.67E-06**	**100.00%**		**2.22E+01**

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

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

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

Risk Impact Due to 10-Year Test Interval

As previously stated, Type A tests impact only Class 3 sequences. For Class 3 sequences, the release magnitude is not impacted by the change in test interval (a small or large breach remains the same, even though the probability of not detecting the breach increases). Thus, only the frequency of Class 3a and Class 3b sequences is impacted. The risk contribution is changed based on the NEI guidance as described in Section 5.1.3 by a factor of 10/3 compared to the base case values. The Class 3a and 3b frequencies are calculated as follows:

$$Freq_{U1Class3a10yr} = \frac{10}{3} * \frac{2}{217} * (CDF - LERF) = \frac{10}{3} * \frac{2}{217} * (5.00\text{E-}06 - 1.78\text{E-}07) = 1.48\text{E-}07$$

$$Freq_{U2Class3a10yr} = \frac{10}{3} * \frac{2}{217} * (CDF - LERF) = \frac{10}{3} * \frac{2}{217} * (4.67\text{E-}06 - 1.74\text{E-}07) = 1.38\text{E-}07$$

$$Freq_{U1Class3b10yr} = \frac{10}{3} * \frac{.5}{218} * (CDF - LERF) = \frac{10}{3} * \frac{.5}{218} * (5.00\text{E-}06 - 1.78\text{E-}07) = 3.69\text{E-}08$$

$$Freq_{U2Class3b10yr} = \frac{10}{3} * \frac{.5}{218} * (CDF - LERF) = \frac{10}{3} * \frac{.5}{218} * (4.67\text{E-}06 - 1.74\text{E-}07) = 3.44\text{E-}08$$

The results of the calculation for a 10-year interval are presented in Table 5-11 for Unit 1 and Table 5-12 for Unit 2.

Table 5-11 – Unit 1 Risk Profile for Once in 10 Year ILRT

Class	Description	Frequency (/yr)	Contribution (%)	Population Dose (person-rem)	Population Dose Rate (person-rem/yr)
1	No containment failure[2]	1.97E-06	39.49%	6.58E+02	1.30E-03
2	Large containment isolation failures	5.98E-08	1.20%	7.40E+05	4.42E-02
3a	Small isolation failures (liner breach)	1.48E-07	2.96%	6.58E+03	9.74E-04
3b	Large isolation failures (liner breach)	3.69E-08	0.74%	6.58E+04	2.42E-03
4	Small isolation failures - failure to seal (type B)	ε[1]	ε[1]	ε[1]	ε[1]
5	Small isolation failures - failure to seal (type C)	ε[1]	ε[1]	ε[1]	ε[1]
6	Containment isolation failures (dependent failure, personnel errors)	ε[1]	ε[1]	ε[1]	ε[1]
7	Severe accident phenomena induced failure (early and late)	2.78E-06	55.60%	8.49E+06	2.36E+01
8	Containment bypass	4.55E-10	0.01%	4.86E+05	2.21E-04
	Total	**5.00E-06**			**2.37E+01**

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

Table 5-12 – Unit 2 Risk Profile for Once in 10 Year ILRT

Class	Description	Frequency (/yr)	Contribution (%)	Population Dose (person-rem)	Population Dose Rate (person-rem/yr)
1	No containment failure[2]	1.84E-06	39.50%	6.58E+02	1.21E-03
2	Large containment isolation failures	4.85E-08	1.04%	7.40E+05	3.59E-02
3a	Small isolation failures (liner breach)	1.38E-07	2.96%	6.58E+03	9.08E-04
3b	Large isolation failures (liner breach)	3.44E-08	0.74%	6.58E+04	2.26E-03
4	Small isolation failures - failure to seal (type B)	ε[1]	ε[1]	ε[1]	ε[1]
5	Small isolation failures - failure to seal (type C)	ε[1]	ε[1]	ε[1]	ε[1]
6	Containment isolation failures (dependent failure, personnel errors)	ε[1]	ε[1]	ε[1]	ε[1]
7	Severe accident phenomena induced failure (early and late)	2.60E-06	55.76%	8.49E+06	2.21E+01
8	Containment bypass	4.76E-10	0.01%	4.86E+05	2.31E-04
	Total	**4.67E-06**			**2.22E+01**

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

Risk Impact Due to 15-Year Test Interval

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

$$Freq_{U1Class3a15yr} = \frac{15}{3} * \frac{2}{217} * (CDF - LERF) = 5 * \frac{2}{217} * (5.00\text{E-}06 - 1.78\text{E-}07) = 2.22\text{E-}07$$

$$Freq_{U2Class3a15yr} = \frac{15}{3} * \frac{2}{217} * (CDF - LERF) = 5 * \frac{2}{217} * (4.67\text{E-}06 - 1.74\text{E-}07) = 2.07\text{E-}07$$

$$Freq_{U1Class3b15yr} = \frac{15}{3} * \frac{.5}{218} * (CDF - LERF) = 5 * \frac{.5}{218} * (5.00\text{E-}06 - 1.78\text{E-}07) = 5.53\text{E-}08$$

$$Freq_{U2Class3b15yr} = \frac{15}{3} * \frac{.5}{218} * (CDF - LERF) = 5 * \frac{.5}{218} * (4.67\text{E-}06 - 1.74\text{E-}07) = 5.16\text{E-}08$$

The results of the calculation for a 15-year interval are presented in Table 5-13 for Unit 1 and Table 5-14 for Unit 2.

Table 5-13 – Unit 1 Risk Profile for Once in 15 Year ILRT

Class	Description	Frequency (/yr)	Contribution (%)	Population Dose (person-rem)	Population Dose Rate (person-rem/yr)
1	No containment failure[2]	1.88E-06	37.64%	6.58E+02	1.24E-03
2	Large containment isolation failures	5.98E-08	1.20%	7.40E+05	4.42E-02
3a	Small isolation failures (liner breach)	2.22E-07	4.44%	6.58E+03	1.46E-03
3b	Large isolation failures (liner breach)	5.53E-08	1.11%	6.58E+04	3.64E-03
4	Small isolation failures - failure to seal (type B)	ε[1]	ε[1]	ε[1]	ε[1]
5	Small isolation failures - failure to seal (type C)	ε[1]	ε[1]	ε[1]	ε[1]
6	Containment isolation failures (dependent failure, personnel errors)	ε[1]	ε[1]	ε[1]	ε[1]
7	Severe accident phenomena induced failure (early and late)	2.78E-06	55.60%	8.49E+06	2.36E+01
8	Containment bypass	4.55E-10	0.01%	4.86E+05	2.21E-04
	Total	**5.00E-06**			**2.37E+01**

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

Table 5-14 – Unit 2 Risk Profile for Once in 15 Year ILRT

Class	Description	Frequency (/yr)	Contribution (%)	Population Dose (person-rem)	Population Dose Rate (person-rem/yr)
1	No containment failure[2]	1.76E-06	37.65%	6.58E+02	1.16E-03
2	Large containment isolation failures	4.85E-08	1.04%	7.40E+05	3.59E-02
3a	Small isolation failures (liner breach)	2.07E-07	4.44%	6.58E+03	1.36E-03
3b	Large isolation failures (liner breach)	5.16E-08	1.10%	6.58E+04	3.39E-03
4	Small isolation failures - failure to seal (type B)	ε[1]	ε[1]	ε[1]	ε[1]
5	Small isolation failures - failure to seal (type C)	ε[1]	ε[1]	ε[1]	ε[1]
6	Containment isolation failures (dependent failure, personnel errors)	ε[1]	ε[1]	ε[1]	ε[1]
7	Severe accident phenomena induced failure (early and late)	2.60E-06	55.76%	8.49E+06	2.21E+01
8	Containment bypass	4.76E-10	0.01%	4.86E+05	2.31E-04
	Total	**4.67E-06**			**2.22E+01**

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

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

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

Regulatory Guide 1.174 [Reference 4] provides guidance for determining the risk impact of plant-specific changes to the licensing basis. RG 1.174 [Reference 4] defines very small changes in risk as resulting in increases of CDF less than 10^{-6}/year and increases in LERF less than 10^{-7}/year, and small changes in LERF as less than 10^{-6}/year. Since containment accident pressure is credited in support of ECCS performance to mitigate design basis accidents at BSEP, the ILRT extension may impact CDF. A detailed analysis is performed and described in Section 5.2.7; this shows the ILRT extension has only a very small effect on CDF. Therefore, the more relevant risk-impact metric is LERF.

For BSEP, 100% of the frequency of Class 3b sequences can be used as a very conservative first-order estimate to approximate the potential increase in LERF from the ILRT interval extension (consistent with the EPRI guidance methodology). Based on a 10-year test interval from Table 5-11 and Table 5-12, the Class 3b frequency is 3.69E-08/year for Unit 1 and 3.44E-08/year for Unit 2; based on a 15-year test interval from Table 5-13 and Table 5-14, the Class 3b frequency is 5.53E-08/year for Unit 1 and 5.16E-08/year for Unit 2. Thus, the increase in the overall probability of LERF due to Class 3b sequences that is due to increasing the ILRT test

interval from 3 to 15 years is 4.42E-08/year for Unit 1 and 4.12E-08/year for Unit 2. Similarly, the increase due to increasing the interval from 10 to 15 years is 1.84E-08/year for Unit 1 and 1.72E-08/year for Unit 2. As can be seen, even with the conservatisms included in the evaluation (per the EPRI methodology), the estimated change in LERF is within the criteria for a very small change when comparing the 15-year results to the current 10-year requirement and the original 3-year requirement. Table 5-15 summarizes these results.

Table 5-15 – Impact on LERF due to Extended Type A Testing Intervals

ILRT Inspection Interval	Unit 1: 3 Years (baseline)	Unit 1: 10 Years	Unit 1: 15 Years	Unit 2: 3 Years (baseline)	Unit 2: 10 Years	Unit 2: 15 Years
Class 3b (Type A LERF)	1.11E-08	3.69E-08	5.53E-08	1.03E-08	3.44E-08	5.16E-08
ΔLERF (3 year baseline)		2.58E-08	4.42E-08		2.41E-08	4.12E-08
ΔLERF (10 year baseline)			1.84E-08			1.72E-08

The increase in the overall probability of LERF due to Class 3b sequences is less than 10^{-7}. Therefore, the ΔLERF is considered very small [Reference 4].

NEI 94-01 [Reference 1] states that a small population dose is defined as an increase of ≤ 1.0 person-rem per year, or ≤ 1% of the total population dose, whichever is less restrictive for the risk impact assessment of the extended ILRT intervals. As shown in Table 5-16, the results of this calculation meet the dose rate criteria.

Table 5-16 – Impact on Dose Rate due to Extended Type A Testing Intervals

ILRT Inspection Interval	Unit 1: 10 Years	Unit 1: 15 Years	Unit 2: 10 Years	Unit 2: 15 Years
ΔDose Rate (3 year baseline)[1]	2.294E-03	3.932E-03	2.139E-03	3.666E-03
ΔDose Rate (10 year baseline)[1]		1.638E-03		1.528E-03
%ΔDose Rate (3 year baseline)[2]	0.010%	0.017%	0.010%	0.017%
%ΔDose Rate (10 year baseline)[2]		0.007%		0.007%

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

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

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

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

where *f*(ncf) is the frequency of those sequences that do not result in containment failure; this frequency is determined by summing the Class 1 and Class 3a results [Reference 24]. Table 5-17 shows the steps and results of this calculation.

Table 5-17 – Impact on CCFP due to Extended Type A Testing Intervals

ILRT Inspection Interval	Unit 1: 3 Years (baseline)	Unit 1: 10 Years	Unit 1: 15 Years	Unit 2: 3 Years (baseline)	Unit 2: 10 Years	Unit 2: 15 Years
f(ncf) (/yr)	2.15E-06	2.12E-06	2.10E-06	2.01E-06	1.98E-06	1.97E-06
f(ncf)/CDF	0.430	0.425	0.421	0.430	0.425	0.421
CCFP	0.570	0.575	0.579	0.570	0.575	0.579
ΔCCFP (3 year baseline)		0.516%	0.885%		0.515%	0.883%
ΔCCFP (10 year baseline)			0.369%			0.368%

As stated in Section 2.0, a change in the CCFP of up to 1.5% is assumed to be small. The increase in the CCFP from the 3 in 10 year interval to 1 in 15 year interval is 0.885% for Unit 1 and 0.984% for Unit 2. Therefore, this increase is judged to be small.

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

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

The following approach is used to determine the change in likelihood, due to extending the ILRT, of detecting corrosion of the containment steel liner [Section 5.1.5.1 of Reference 24]. This likelihood is then used to determine the resulting change in risk. Consistent with the Calvert Cliffs analysis, the following issues are addressed:

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

<u>Assumptions</u>

- Based on a review of industry events, an Oyster Creek incident is assumed to be applicable to BSEP for a concealed shell failure in the floor. In the Calvert Cliffs analysis, this event was assumed not to be applicable and a half failure was assumed for basemat concealed liner corrosion due to the lack of identified failures (See Table 5-18, Step 1).
- The two corrosion events used to estimate the liner flaw probability in the Calvert Cliffs previous analysis are assumed to still be applicable.
- Consistent with the Calvert Cliffs analysis, the estimated historical flaw probability data period is also limited to 5.5 years to reflect the years since September 1996 when 10 CFR 50.55a started requiring visual inspection. Additional success data was not used to limit the aging impact of this corrosion issue, even though inspections were being

performed prior to this date (and have been performed since the time frame of the Calvert Cliffs analysis) (See Table 5-18, Step 1).

- Consistent with the Calvert Cliffs analysis, the steel liner flaw likelihood is assumed to double every five years. This is based solely on judgment and is included in this analysis to address the increased likelihood of corrosion as the steel liner ages (See Table 5-18, Steps 2 and 3). Sensitivity studies are included that address doubling this rate every ten years and every two years.
- In the Calvert Cliffs analysis, the likelihood of the containment atmosphere reaching the outside atmosphere, given that a liner flaw exists, was estimated as 1.1% for the cylinder and dome, and 0.11% (10% of the cylinder failure probability) for the basemat. These values were determined from an assessment of the probability versus containment pressure. For BSEP, the containment design pressure is 49 psig [References 37 and 38]. Probabilities of 1% for the cylinder and dome, and 0.1% for the basemat are used in this analysis, and sensitivity studies are included in Section 5.3.1 (See Table 5-18, Step 4).
- Consistent with the Calvert Cliffs analysis, the likelihood of leakage escape (due to crack formation) in the basemat region is considered to be less likely than the containment cylinder and dome region (See Table 5-18, Step 4).
- Consistent with the Calvert Cliffs analysis, a 5% visual inspection detection failure likelihood given the flaw is visible and a total detection failure likelihood of 10% is used. To date, all liner corrosion events have been detected through visual inspection (See Table 5-18, Step 5).
- Consistent with the Calvert Cliffs analysis, all non-detectable containment failures are assumed to result in early releases. This approach avoids a detailed analysis of containment failure timing and operator recovery actions.

Table 5-18 – Steel Liner Corrosion Base Case

Step	Description	Containment Cylinder and Dome (85%)		Containment Basemat (15%)	
1	Historical liner flaw likelihood Failure data: containment location specific Success data: based on 70 steel-lined containments and 5.5 years since the 10CFR 50.55a requirements of periodic visual inspections of containment surfaces	Events: 2 (Brunswick 2 and North Anna 2) 2 / (70 x 5.5) = 5.19E-03		Events: 1 1 / (70 x 5.5) = 2.60E-03	
2	Aged adjusted liner flaw likelihood During the 15-year interval, assume failure rate doubles every five years (14.9% increase per year). The average for the 5th to 10th year set to the historical failure rate.	Year	Failure rate	Year	Failure rate
		1 average 5-10 15	2.05E-03 5.19E-03 1.43E-02	1 average 5-10 15	1.03E-03 2.60E-03 7.14E-03
		15 year average = 6.44E-03		15 year average = 3.22E-03	
3	Increase in flaw likelihood between 3 and 15 years Uses aged adjusted liner flaw likelihood (Step 2), assuming failure rate doubles every five years.	0.73% (1 to 3 years) 4.18% (1 to 10 years) 9.66% (1 to 15 years)		0.36% (1 to 3 years) 2.08% (1 to 10 years) 4.82% (1 to 15 years)	
4	Likelihood of breach in containment given liner flaw	1%		0.1%	
5	Visual inspection detection failure likelihood	10% 5% failure to identify visual flaws plus 5% likelihood that the flaw is not visible (not through-cylinder but could be detected by ILRT). All events have been detected through visual inspection. 5% visible failure detection is a conservative assumption.		100% Cannot be visually inspected	
6	Likelihood of non-detected containment leakage (Steps 3 x 4 x 5)	0.00073% (3 years) 0.73% x 1% x 10% 0.00418% (10 years) 4.18% x 1% x 10% 0.00966% (15 years) 9.66% x 1% x 10%		0.000360% (3 years) 0.36% x 0.1% x 100% 0.00208% (10 years) 2.08% x 0.1% x 100% 0.00482% (15 years) 4.82% x 0.1% x 100%	

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

Table 5-19 – Total Likelihood on Non-Detected Containment Leakage Due to Corrosion for BSEP

Description
At 3 years: 0.00073% + 0.000360% = 0.00109%
At 10 years: 0.00418% + 0.00208% = 0.00626%
At 15 years: 0.00966% + 0.00482% = 0.01448%

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

The two corrosion events that were initiated from the non-visible (backside) portion of the containment liner used to estimate the liner flaw probability in the Calvert Cliffs analysis are assumed to be applicable to this containment analysis. These events, one at North Anna Unit 2 (September 1999) caused by timber embedded in the concrete immediately behind the containment liner, and one at Brunswick Unit 2 (April 1999) caused by a cloth work glove embedded in the concrete next to the liner, were initiated from the nonvisible (backside) portion of the containment liner. A search of the NRC website LER database identified two additional events have occurred since the Calvert Cliffs analysis was performed and another event at a BWR screened in the Calvert Cliffs analysis as not applicable. In January 2000, a 3/16-inch circular through-liner hole was found at Cook Nuclear Plant Unit 2 caused by a wooden brush handle embedded immediately behind the containment liner. The other event occurred in April 2009, where a through-liner hole approximately 3/8-inch by 1-inch in size was identified in the Beaver Valley Power Station Unit 1 (BVPS-1) containment liner caused by pitting originating from the concrete side due to a piece of wood that was left behind during the original construction that came in contact with the steel liner [Reference 29]. Two other containment liner through-wall hole events occurred at Turkey Point Units 3 and 4 in October 2010 and November 2006, respectively. However, these events originated from the visible side caused by the failure of the coating system, which was not designed for periodic immersion service, and are not considered to be applicable to this analysis. More recently, in October 2013, some through-wall containment liner holes were identified at BVPS-1, with a combined total area of approximately 0.395 square inches. The cause of these through-wall liner holes was attributed to corrosion originating from the outside concrete surface due to the presence of rayon fiber foreign material that was left behind during the original construction and was contacting the steel liner [Reference 28]. In the mid-1980s, Oyster Creek identified corrosion of the shell of the containment drywell in the sandbed region [Reference 25]. For risk evaluation purposes, these six total corrosion events occurring in 66 operating plants with steel containment liners over a 17.1 year period from September 1996 to October 4, 2013 (i.e., 6/(66*17.1) = 5.32E-03) are bounded by the estimated historical flaw probability based on the three events in the 5.5 year period of the Calvert Cliffs analysis (i.e., 3/(70*5.5) = 7.79E-03) incorporated in the EPRI guidance.

5.2.7 Containment Accident Pressure Evaluation

In general, CDF is not significantly impacted by an extension of the ILRT interval; however, plants that rely on containment accident pressure (CAP), also referred to as containment overpressure (COP), for net positive suction head (NPSH) for emergency core coolant system (ECCS) injection for certain accident sequences may experience an increase in CDF [Reference 24]. BSEP credits CAP in support of ECCS performance to mitigate design basis accidents; a loss of CAP may lead to degraded or a total loss of ECCS pump flow. Therefore, a detailed analysis was performed to quantify the potential effect on CDF [Reference 51]. This section provides an overview and summary of the Reference 51 analysis and the results.

Per the EPRI guidance [Reference 24]:

In the case where containment overpressure may be a consideration, plants should examine their ECCS NPSH requirements to determine if containment overpressure is required (and assumed to be available) in various accident scenarios. Examples include the following:

- *LOCA scenarios where the initial containment pressurization helps to satisfy the NPSH requirements for early injection in BWRs or PWR sump recirculation*
- *Total loss of containment heat removal scenarios where gradual containment pressurization helps to satisfy the NPSH requirements for long-term use of an injection system from a source inside of containment (for example, BWR suppression pool).*

In a design basis LOCA event, for long-term (greater than 600 seconds) post-LOCA operation, up to 5.0 psig of CAP is credited at BSEP to ensure adequate NPSH margin (NPSH available minus NPSH required); for short-term (less than 600 seconds) operation the NPSH margin is sufficient and no credit for CAP is needed [Reference 27 Section 6.3.2.2.5]. Therefore, LOCA sequences must be analyzed for an impact from a loss of CAP. In the PRA, All LOCA sequences are considered, which includes all modeled RCS pipe breaks and transient-induced LOCAs (e.g., inadvertent safety relief valve (SRV) opening without closure).

Further, the EPRI guidance states

If either of these cases is susceptible to whether or not containment overpressure is available (or other cases are identified), then the PRA model should be adjusted to account for this requirement.

The BSEP PRA also credits CAP for the intermittent use of long-term injection systems with suction from the suppression pool for transient sequences where suppression pool cooling is failed; this function requires an elevated pressure in containment to support NPSH to the ECCS. Therefore, transient sequences must be analyzed for an impact from a loss of CAP.

The effect of a loss of CAP on CDF was analyzed for both internal and external events.

5.2.7.1 Loss of CAP Analysis

A loss of CAP may lead to failure of the low pressure ECCS systems, RHR and Core Spray, due to inadequate NPSH available to support required pump flow. Suppression pool cooling (SPC) can be initiated to lower the suppression pool temperature (SPT) and increase the available NPSH. In other words, CAP is not required if suppression pool cooling is successfully established in time to preclude SPT from exceeding the value where available NPSH would decrease below that required to support pump flow. If SPC is not initiated in time or fails, the intermittent use of the low pressure ECCS systems for post-vent, long-term injection for

transient scenarios credits elevated containment pressure to function. Given the possible existence of a pre-existing leak in containment evaluated in this risk analysis, these long-term injection sources may be failed if SPC is not successful.

The approach to modeling the risk impact due to the potential for loss of CAP given a pre-existing leak involved two model changes:

- First, the PRA timing for the operator actions to establish SPC was confirmed adequate to preclude the need for CAP. Timing was verified for all accident sequences where low pressure ECCS systems are credited, and, if the existing operator action timing was not adequate to preclude the need for CAP, the model was adjusted to include the required (shorter) operator action timing. The details are discussed below.

- Second, the PRA model was adjusted to ensure low pressure ECCS systems were failed if suppression pool cooling fails, which models the impacts of inadequate NPSH given the pre-existing leak, no SPC, but sequences where containment venting succeeds and long term low pressure injection is required.

<u>MAAP Analyses Inputs</u>

In order to establish the operator action timing for initiating SPC in time to preclude the need for CAP for low pressure ECCS NPSH, existing MAAP analyses and new MAAP analyses cases were utilized.

MAAP analyses supporting the Fire PRA were performed in Reference 39 in order to analyze the effect of a loss of CAP due to multiple spurious operations (MSOs) that result in an un-isolated containment on the low pressure ECCS systems. Review of these cases determined they are applicable/bounding for transient sequences in the BSEP PRA because the un-isolated containment ensures no CAP can build to support low pressure ECCS NPSH, and the fire PRA is composed of mostly transient risk. According to the Fire PRA MAAP analysis, a suppression pool temperature (SPT) of 192 °F will degrade RHR pump flow and a SPT of 202 °F will degrade the Core Spray flow. It was determined that if SPC is initiated when the SPT reaches 185 °F, the SPT will remain below these criteria. Per the Fire PRA MAAP results, the most limiting timing for initiating SPC with an un-isolated containment is 3.69 hours. The operator action to initiate SPC following a non-LOCA in the PRA models is OPER-SPCE, which has a timing of 3.8 hours. This small difference in time leads to no change in the HEP value, and thus no change in risk; therefore, the modeled operator action to initiate SPC for a transient sequence is considered appropriate for the loss of CAP analysis.

Existing MAAP analyses were applicable to transient risk in the BSEP PRA, but do not apply to RCS pipe break LOCA conditions and the heatup timing of the suppression pool in LOCA sequences. To establish the timing required to initiate SPC given an RCS pipe break LOCA to preclude the need for CAP, MAAP runs were performed for small, medium, and large LOCA scenarios for the CAP analysis using similar methodology to the Fire PRA MAAP analyses discussed above. Per the BSEP Level 2 analysis [Reference 18], a 2-inch diameter opening in containment equates to a leak rate of 30 – 35 wt.%/day, and an opening size of 3.5-inches equates to 100 wt.%/day. Per Section 5.2.2, allowable containment leakage, La, is 0.5 wt.%/day; therefore, 100La is 50 wt.%/day, which approximately equates to an opening size of 2.5-inches in diameter. Therefore, the loss of CAP LOCA analyses assume a containment opening size of 2.5 inches; minor changes in the size of the opening have little impact on the results.

The results of the CAP analysis MAAP runs indicate that initiating SPC at 2.4 hours for small and medium LOCAs and 1.75 hours for large LOCAs prevents reaching the SPT criterion. Using these timings, two detailed HFEs were created for initiating SPC with loss of CAP, one for small and medium LOCAs and one for large LOCAs. The HFEs were based off operator action OPER-SPC, which is the operator action to initiate SPC following a LOCA. The BSEP PRA model was adjusted to utilize these HFEs for LOCA scenarios to model the time in which SPC must be initiated to preclude the need for CAP to support low pressure ECCS NPSH.

Model Adjustment

With the timing to initiate SPC to preclude the need for CAP to support low pressure ECCS NPSH established via the MAAP analyses, the Unit 1 and Unit 2 models (Internal and External Events) were revised. The revised CAP analysis models include failure of the low pressure ECCS systems (RHR and Core Spray) given a pre-existing leak in containment and failure to initiate SPC in time to preclude the need for CAP to support low pressure ECCS NPSH (new HFEs) in all applicable sequences in each model. For the purposes of this risk assessment, internal events models are the full-power internal events and internal flooding PRA models; external event models are Fire PRA and High Winds PRA models. The CAP analysis Unit 1 and Unit 2 models were quantified to estimate the change in CDF from the increased likelihood of pre-existing leaks given the ILRT surveillance frequency change.

The pre-existing leak basic event probability was varied from 2.30E-03 (probability of a 3b leak based on an ILRT interval of 3-in-10 years) to 1.15E-02 (probability of a 3b leak based on the ILRT interval of 1-in-15 years) and the CDF for each surveillance frequency was estimated and the ΔCDF was estimated as the difference between the two surveillance frequency cases. The ΔCDF was also estimated for the 1-in-10 years ILRT interval by changing the pre-existing leak basic event probability to 7.67E-03.

Quantification Results

The results of the analysis are provided below and summarized in Table 5-20 for Unit 1 and Table 5-21 for Unit 2.

The CDF increase due to a loss of CAP due to the ILRT extension to 1-in-15 years from 3-in-10 years is estimated to be 1.61E-08/year for Unit 1 and 1.54E-08/year for Unit 2. This ΔCDF was assumed equal to ΔLERF from CAP and added to the EPRI Class 3b frequency and included in the results provided in Section 6.0 and in the sensitivities performed in Section 5.3. The CDF increase due to a loss of CAP due to the ILRT extension to 1-in-10 years from 3-in-10 years is estimated to be 9.37E-09/year for Unit 1 and 9.01E-09/year for Unit 2.

Similarly for high wind events, the pre-existing leak basic event probability was varied from 2.30E-03 to 1.15E-02, which causes a delta of 6.41E-08 for Unit 1 and 6.31E-08 for Unit 2. This ΔCDF was assumed equal to ΔLERF from CAP and added to the EPRI Class 3b frequency for high winds events in the external events analysis (Section 5.2.8). The CDF increase due to a loss of CAP due to the ILRT extension to 1-in-10 years from 3-in-10 years is estimated to be 3.75E-08/year for Unit 1 and 3.69E-08/year for Unit 2.

For fire events, the quantification showed no increase in CDF due to the pre-existing leak in containment; therefore, there is a negligible change in CDF due to the ILRT extension.

For seismic events, a qualitative and bounding CAP analysis was performed. Since BSEP credits the use of RHR and Core Spray for long-term intermittent injection for transient sequences, there may be some impact to seismic CDF due to a loss of CAP. Generally, seismic risk is dominated by failure of key plant structures and key plant systems due to seismic motion which exceeds the capacity of the key structures and systems. Failure of key structures (containment building, reactor building, etc.) are typically assumed to lead straight to core damage; and therefore, a loss of CAP will have no impact. It is common to treat equipment of the same type at the same elevation as being failed due to the seismic event, so seismic events that fail all low pressure ECCS pumps are much more likely than seismic events that only fail some low pressure ECCS pumps while others survive; a loss of CAP will have no impact on scenarios where all ECCS pumps are failed. Furthermore, a loss of CAP will have no impact on station blackout (SBO) scenarios, since the ECCS pumps will be failed due to a loss of power. A loss of CAP may impact seismic scenarios where a key structure is not failed and the low pressure ECCS pumps are available. As a bounding estimate, the ΔCDF for seismic scenarios is assumed proportional to the ΔCDF for Internal Events. This is bounding because the predominant contributor to the increase due to a loss of CAP for Internal Events is LOCA sequences and seismic events are far more likely to lead to key structure and system failures or SBO sequences than LOCA sequences. This leads to a seismic ΔCDF of 3.02E-08 for Unit 1 and 3.10E-08 for Unit 2. These ΔCDFs were assumed equal to ΔLERF from CAP and added to the EPRI Class 3b frequency for seismic events in the external events analysis (Section 5.2.8). The CDF increase due to a loss of CAP due to the ILRT extension to 1-in-10 years from 3-in-10 years is estimated to be 1.76E-08/year for Unit 1 and 1.81E-08/year for Unit 2.

Table 5-20 – Unit 1 CAP Analysis Results

Model	Results	Notes
Internal Events/Internal Flooding PRA	ΔCDF = 1.61E-08/year ΔCDF was assumed equal to ΔLERF from CAP and added to the EPRI Class 3b frequency for Internal Events	N/A
High Winds PRA	ΔCDF = 6.41E-08/year ΔCDF was assumed equal to ΔLERF from CAP and added to the EPRI Class 3b frequency for high wind events	Increase due to CAP related NPSH failure of RHR and Core Spray in sequences where SPC is failed and containment venting is established as the method of decay heat removal. Conservative, as FLEX is not credited in the High Winds models, which would largely reduce this increase
Fire PRA	No ΔCDF due to loss of CAP	Fire PRA does not credit intermittent use of long-term injection systems with suction from the suppression pool where SPC is failed
Seismic PRA	ΔCDF = 3.02E-08/year ΔCDF was assumed equal to ΔLERF from CAP and added to the EPRI Class 3b frequency for seismic events	Seismic ΔCDF assumed proportional to ΔCDF for Internal Events. This is conservative, as most seismic scenarios would be unaffected by a loss of CAP and seismic events typically do not lead to LOCA sequences.
	Total ΔCDF = 1.10E-07/year	

Table 5-21 – Unit 2 CAP Analysis Results

Model	Results	Notes
Internal Events/Internal Flooding PRA	ΔCDF = 1.54E-08/year ΔCDF was assumed equal to ΔLERF from CAP and added to the EPRI Class 3b frequency for Internal Events	N/A
High Winds PRA	ΔCDF = 6.31E-08/year ΔCDF was assumed equal to ΔLERF from CAP and added to the EPRI Class 3b frequency for high wind events	Increase due to CAP related NPSH failure of RHR and Core Spray in sequences where SPC is failed and containment venting is established as the method of decay heat removal. Conservative, as FLEX is not credited in the High Winds models, which would largely reduce this increase
Fire PRA	No ΔCDF due to loss of CAP	Fire PRA does not credit intermittent use of long-term injection systems with suction from the suppression pool where SPC is failed
Seismic PRA	ΔCDF = 3.10E-08/year ΔCDF was assumed equal to ΔLERF from CAP and added to the EPRI Class 3b frequency for seismic events	Seismic ΔCDF assumed proportional to ΔCDF for Internal Events. This is conservative, as most seismic scenarios would be unaffected by a loss of CAP and seismic events typically do not lead to LOCA sequences.
	Total ΔCDF = 1.10E-07/year	

Regulatory Guide 1.174 [Reference 4] defines very small changes in CDF as resulting in increases of CDF less than 1.0E-06/year. Per this analysis, the change in CDF due to a loss of CAP and the ILRT extension is “very small”.

5.2.7.2 Key Assumptions and Sources of Uncertainty

Key assumptions or sources of uncertainty for the loss of CAP analysis are the following [Reference 51]:

- No credit is given for alignment of Core Spray to the Condensate Storage Tank (CST), a source outside containment. Procedures are in place to align Core Spray to the CST. Aligning the Core Spray pumps to the CST would significantly reduce CDF for single unit events. Not crediting Core Spray alignment to the CST is conservative.
- Another source of uncertainty is whether or not a "large" "early" release would occur in a loss of NPSH scenario. This uncertainty is addressed with the CAP related assumption that loss of low pressure injection (Core Spray and RHR) due to a pre-existing leak and loss of SPC leads to a large early release. This may be a conservative assumption. Loss of inventory make-up may result in a delayed "non-Large" release, for which there would be adequate time for evacuation.
- FLEX is not modeled in the External Events models; and therefore, was not credited in the External Events loss of CAP analysis. Crediting FLEX would reduce the increase due to a loss of CAP for High Winds events, since FLEX is a separate form of late injection that would likely be available even if the intermittent long-term use of the low pressure ECCS systems was failed due to a loss of CAP. Similarly, FLEX would reduce

the risk from seismic events given a loss of CAP; however, seismic events were not quantitatively analyzed in the CAP analysis.

- It is assumed the low pressure ECCS pumps will fail when the SPT criteria is met. The reduction in NPSH may not lead to immediate failure of the pumps, and instead, may only degrade the flow. Furthermore, it is noted that industry testing and analysis indicate that emergency core cooling system ECCS pumps used in boiling water reactor (BWR) 3/4 plants are capable of adequate short term (i.e., ~24 hr) operation well below the manufacturer's recommended design NPSH (e.g., 65% of the specified NPSH limit for Browns Ferry as documented in NUREG/CR-2973 [Reference 49]). Therefore, additional margin exists beyond that reflected in the MAAP calculations.
- MAAP is known to have some modeling deficiencies (e.g., potential for reverse flow not modeled) for Large LOCA scenarios. These deficiencies only impact results in the early portion of the run (i.e., approximately first three minutes) prior to core recovery. These deficiencies do not impact the ILRT MAAP calculation results because the peak torus temperature is reached hours into each run.

5.2.8 Potential Impact from External Events Contribution

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

Brunswick has transitioned to NFPA 805 licensing basis for fire protection [Reference 30] and all modifications supporting the transition have been implemented. Therefore, the NFPA 805 post-modification Fire PRA model is deemed applicable and was used for this calculation.

The Revision 5 Fire PRA model was used to obtain the fire CDF and LERF values [References 17 and 32]. To reduce conservatism in the model, the methodology of subtracting existing LERF from CDF is also applied to the Fire PRA model. The following shows the calculation for Class 3b:

$$Freq_{U1class3b} = P_{class3b} * (CDF - LERF) = \frac{0.5}{218} * (2.09E\text{-}5 - 4.58E\text{-}6) = 3.74\text{E-}08$$

$$Freq_{U2class3b} = P_{class3b} * (CDF - LERF) = \frac{0.5}{218} * (2.45E\text{-}5 - 4.53E\text{-}6) = 4.58\text{E-}08$$

$$Freq_{U1class3b10yr} = \frac{10}{3} * P_{class3b} * (CDF - LERF) = \frac{10}{3} * \frac{0.5}{218} * (2.09E\text{-}5 - 4.58E\text{-}6) = 1.25\text{E-}07$$

$$Freq_{U2class3b10yr} = \frac{10}{3} * P_{class3b} * (CDF - LERF) = \frac{10}{3} * \frac{0.5}{218} * (2.45E\text{-}5 - 4.53E\text{-}6) = 1.53\text{E-}07$$

$$Freq_{U1class3b15yr} = \frac{15}{3} * P_{class3b} * (CDF - LERF) = 5 * \frac{0.5}{218} * (2.09E\text{-}5 - 4.58E\text{-}6) = 1.87\text{E-}07$$

$$Freq_{U2class3b15yr} = \frac{15}{3} * P_{class3b} * (CDF - LERF) = 5 * \frac{0.5}{218} * (2.45E\text{-}5 - 4.53E\text{-}6) = 2.29\text{E-}07$$

The 2014 Seismic Reevaluations for operating reactor sites [Reference 33] states the conclusions reached in 2010 by GI-199 [Reference 34] remain valid for estimating Seismic CDF at plants in the Central and Eastern United States, which includes BSEP. EPRI guidance [Reference 35] on recent seismic evaluations states, "EPRI does not recommend using any very conservative approaches to estimate the SCDF such as use of the maximum SCDFs calculated at any one frequency. This type of bounding approach is overly conservative and judged to not provide realistic risk estimates consistent with SCDFs calculated in actual SPRAs." Therefore, the simple average of 9.40E-06 reported in Table D-1 of GI-199 [Reference 34] is used for the Seismic CDF. Since no Seismic LERF value is calculated, it is assumed the LERF/CDF ratio will be similar for seismic risk as for internal events risk. Applying the internal event LERF/CDF ratio

to the seismic CDF yields an estimated seismic LERF of 3.35E-07 for Unit 1 and 3.51E-07 for Unit 2, as shown by the equations below.

$$\mathrm{LERF_{U1Seismic}} \approx \mathrm{CDF_{U1Seismic}} * \mathrm{LERF_{U1IE}} / \mathrm{CDF_{U1IE}} = 9.40\mathrm{E}\text{-}06 * 1.78\mathrm{E}\text{-}07 / 5.00\mathrm{E}\text{-}06 = 3.35\mathrm{E}\text{-}07$$

$$\mathrm{LERF_{U2Seismic}} \approx \mathrm{CDF_{U2Seismic}} * \mathrm{LERF_{U2IE}} / \mathrm{CDF_{U2IE}} = 9.40\mathrm{E}\text{-}06 * 1.74\mathrm{E}\text{-}07 / 4.67\mathrm{E}\text{-}06 = 3.51\mathrm{E}\text{-}07$$

Subtracting seismic LERF from CDF, the Class 3b frequency can be calculated by the following formulas:

$$Freq_{U1class3b} = P_{class3b} * (CDF - LERF) = \frac{0.5}{218} * (9.40E\text{-}6 - 3.35E\text{-}7) = 2.08\mathrm{E}\text{-}08$$

$$Freq_{U2class3b} = P_{class3b} * (CDF - LERF) = \frac{0.5}{218} * (9.40E\text{-}6 - 3.51E\text{-}7) = 2.08\mathrm{E}\text{-}08$$

$$Freq_{U1class3b10yr} = \frac{10}{3} * P_{class3b} * (CDF - LERF) = \frac{10}{3} * \frac{0.5}{218} * (9.40E\text{-}6 - 3.35E\text{-}7) = 6.93\mathrm{E}\text{-}08$$

$$Freq_{U2class3b10yr} = \frac{10}{3} * P_{class3b} * (CDF - LERF) = \frac{10}{3} * \frac{0.5}{218} * (9.40E\text{-}6 - 3.51E\text{-}7) = 6.92\mathrm{E}\text{-}08$$

$$Freq_{U1class3b15yr} = \frac{15}{3} * P_{class3b} * (CDF - LERF) = 5 * \frac{0.5}{218} * (9.40E\text{-}6 - 3.35E\text{-}7) = 1.04\mathrm{E}\text{-}07$$

$$Freq_{U2class3b15yr} = \frac{15}{3} * P_{class3b} * (CDF - LERF) = 5 * \frac{0.5}{218} * (9.40E\text{-}6 - 3.51E\text{-}7) = 1.04\mathrm{E}\text{-}07$$

The High Winds PRA results estimate a CDF of 1.98E-05/year and a LERF of 4.69E-08/year for Unit 1 and a CDF of 1.81E-05/year and a LERF of 4.40E-08/year for Unit 2 [Reference 17]. Subtracting high winds LERF from CDF, the Class 3b frequency can be calculated by the following formulas:

$$Freq_{U1class3b} = P_{class3b} * (CDF - LERF) = \frac{0.5}{218} * (1.98E\text{-}6 - 4.69E\text{-}8) = 4.43\mathrm{E}\text{-}09$$

$$Freq_{U2class3b} = P_{class3b} * (CDF - LERF) = \frac{0.5}{218} * (1.81E\text{-}6 - 4.40E\text{-}8) = 4.05\mathrm{E}\text{-}09$$

$$Freq_{U1class3b10yr} = \frac{10}{3} * P_{class3b} * (CDF - LERF) = \frac{10}{3} * \frac{0.5}{218} * (1.98E\text{-}6 - 4.69E\text{-}8) = 1.48\mathrm{E}\text{-}08$$

$$Freq_{U2class3b10yr} = \frac{10}{3} * P_{class3b} * (CDF - LERF) = \frac{10}{3} * \frac{0.5}{218} * (1.81E\text{-}6 - 4.40E\text{-}8) = 1.35\mathrm{E}\text{-}08$$

$$Freq_{U1class3b15yr} = \frac{15}{3} * P_{class3b} * (CDF - LERF) = 5 * \frac{0.5}{218} * (1.98E\text{-}6 - 4.69E\text{-}8) = 2.22\mathrm{E}\text{-}08$$

$$Freq_{U2class3b15yr} = \frac{15}{3} * P_{class3b} * (CDF - LERF) = 5 * \frac{0.5}{218} * (1.81E\text{-}6 - 4.40E\text{-}8) = 2.03\mathrm{E}\text{-}08$$

The CAP analysis performed in Section 5.2.7 determined that a loss of CAP may lead to an increase in CDF for high winds and seismic events given the ILRT extension to 1 in 15 years. This ΔCDF was assumed equal to ΔLERF from CAP and added to the EPRI Class 3b frequencies calculated above for high winds and seismic:

<u>Seismic</u>

$$Freq_{U1class3b10yr} = 6.93E\text{-}08 + 1.76E\text{-}08 = 8.69\mathrm{E}\text{-}08$$

$$Freq_{U2class3b10yr} = 6.92E\text{-}08 + 1.81E\text{-}08 = 8.73\mathrm{E}\text{-}08$$

$$Freq_{U1class3b15yr} = 1.04E\text{-}07 + 3.02E\text{-}08 = 1.34\mathrm{E}\text{-}07$$

$$Freq_{U2class3b15yr} = 1.04E\text{-}07 + 3.10E\text{-}08 = 1.35\mathrm{E}\text{-}07$$

High Winds

$$Freq_{U1class3b10yr} = 1.48E\text{-}08 + 3.75E\text{-}08 = 5.23\text{E-}08$$

$$Freq_{U2class3b10yr} = 1.35E\text{-}08 + 3.69E\text{-}08 = 5.04\text{E-}08$$

$$Freq_{U1class3b15yr} = 2.22E\text{-}08 + 6.41E\text{-}08 = 8.63\text{E-}08$$

$$Freq_{U2class3b15yr} = 2.03E\text{-}08 + 6.31E\text{-}08 = 8.34\text{E-}08$$

The fire, seismic, and high winds contributions to Class 3b frequencies are then combined to obtain the total external event contribution to Class 3b frequencies. The change in LERF is calculated for the 1 in 10 year and 1 in 15 year cases and the change defined for the external events in Table 5-22 for Unit 1 and Table 5-23 for Unit 2.

Table 5-22 – Unit 1 BSEP External Event Impact on ILRT LERF Calculation

Hazard	EPRI Accident Class 3b Frequency			LERF Increase (from 3 per 10 years to 1 per 15 years)
	3 per 10 year	1 per 10 year	1 per 15 years	
External Events	6.27E-08	2.64E-07	4.08E-07	3.45E-07
Internal Events	1.11E-08	4.62E-08	7.14E-08	6.03E-08
Combined	7.37E-08	3.10E-07	4.79E-07	4.05E-07

Table 5-23 – Unit 2 BSEP External Event Impact on ILRT LERF Calculation

Hazard	EPRI Accident Class 3b Frequency			LERF Increase (from 3 per 10 years to 1 per 15 years)
	3 per 10 year	1 per 10 year	1 per 15 years	
External Events	7.06E-08	2.90E-07	4.47E-07	3.77E-07
Internal Events	1.03E-08	4.34E-08	6.70E-08	5.67E-08
Combined	8.09E-08	3.34E-07	5.14E-07	4.33E-07

The internal event results are also provided to allow a composite value to be defined. When both the internal and external event contributions are combined, the total change in LERF of 4.08E-07 for Unit 1 and 4.36E-07 for Unit 2 meets the guidance for small change in risk, as it exceeds 1.0E-07/yr and remains less than 1.0E-06 change in LERF. For this change in LERF to be acceptable, total LERF must be less than 1.0E-05. The total LERF value is calculated below:

$$\mathrm{LERF_{U1}} = \mathrm{LERF_{U1internal}} + \mathrm{LERF_{U1Fire}} + \mathrm{LERF\ _{U1Seismic}} + \mathrm{LERF\ _{U1HW}} + \mathrm{LERF_{U1class3Bincrease}}$$

$$= 1.78\text{E-}07/\mathrm{yr} + 4.58\text{E-}06/\mathrm{yr} + 3.35\text{E-}07/\mathrm{yr} + 4.69\text{E-}08/\mathrm{yr} + 4.05\text{E-}07/\mathrm{yr} = 5.55\text{E-}06/\mathrm{yr}$$

$$\mathrm{LERF_{U2}} = \mathrm{LERF_{U2internal}} + \mathrm{LERF_{U2Fire}} + \mathrm{LERF\ _{U2Seismic}} + \mathrm{LERF\ _{U2HW}} + \mathrm{LERF_{U2class3Bincrease}}$$

$$= 1.74\text{E-}07/\mathrm{yr} + 4.53\text{E-}06/\mathrm{yr} + 3.51\text{E-}07/\mathrm{yr} + 4.40\text{E-}08/\mathrm{yr} + 4.33\text{E-}07/\mathrm{yr} = 5.53\text{E-}06/\mathrm{yr}$$

As specified in Regulatory Guide 1.174 [Reference 4], since the total LERF is less than 1.0E-05, it is acceptable for the ΔLERF to be between 1.0E-07 and 1.0E-06.

5.2.8.1 Screened External Hazards

Several "other" external events were evaluated in the BSEP IPEEE [Reference 47] and were subsequently screened using various criteria (e.g., the event cannot occur close enough to the plant to have an effect, core damage frequency is less than 1E-06/year, etc.). As required by NUREG-1407 [Reference 31], detailed analyses of aircraft impact, military facilities, industrial accidents, and transportation accidents were performed in the IPEEE. Since the IPEEE was conducted in 1995, a review of these external hazards was performed for this analysis in order to verify that the screening is valid for this application.

Two types of aircraft impacts were evaluated, military or commercial aircraft and general aviation [Reference 47]. The closest airport with military operations is the Wilmington International Airport (formerly New Hanover County Airport). A frequency of impact by military or commercial aircraft from this airport was estimated to be 1E-08/year, so even a ten-fold increase in frequency to 1E-07/year due to increased operations at the airport would still be low enough to screen the hazard. The closest general aviation airport is Cape Fear Regional Jetport (formerly Brunswick County Airport). There were 33,000 aircraft operations at this airport per year according to 1992 FAA data [Reference 47]. Using this number of aircraft operations, a frequency of airstrike was calculated as 1.3E-06/year, and using a very conservative estimate of 0.1 for the CCDP, the CDF was estimated as 1.3E-07/year. According to updated FAA data from 2017 [Reference 48], the Cape Fear Regional Airport now has 77,000 operations per year, which is a 133% increase in aircraft operations. Assuming a proportional increase in CDF leads to a CDF of 3.03E-07/year. Therefore, the total risk from aircraft impacts is 4.03E-07/year, which is sufficiently low to screen the hazard.

Military accidents were analyzed for impact on the BSEP site. Sunny Point Munitions storage facility is located 4 miles north of BSEP [Reference 47]. The largest concentration of explosives is two fully loaded barges equivalent to 19.2 million pounds of TNT. The results of a study that evaluated the explosion of 20,000,000 pounds of TNT found that the blast pressure at BSEP would be 0.5 psi overpressure and 1.0 psi reflected overpressure. These are less than the tornado loads of the BSEP Class I buildings [Reference 47]. As there has been no change to the structural integrity of the Class I buildings, the screening of this hazard is valid.

There are three significant industrial facilities near BSEP, the Archer Daniel Midland (ADM) facility, the natural gas pipeline, and the Southport Power Plant (formerly the Co-Gentrix plant). Per the IPEEE [Reference 47], any explosions from the ADM facility will be of a less magnitude than the Sunny Point Munitions facility and that toxic chemicals are limited, and thus, are not a concern to the BSEP site [Reference 47]. The worst type of accident at the Southpoint Power Plant is a high energy line break, but that would not be worse than the same event at BSEP, which is within the design basis. The gas pipeline was analyzed for effects of radiant heat on the site given a pipe break and fire, as well as, the effect of methane on control room habitability; neither issue is a concern for BSEP [Reference 47]. The screening of this hazard remains valid.

Transportation impacts due to barge/ship traffic on the Cape Fear River and from road traffic on Highway 87 were evaluated. The most severe transportation accident is a munitions barge with 10,000,000 pounds of TNT detonating on the Cape Fear River or a vehicle with 50,000 pounds of TNT detonating on Highway 87. These are bounded by the explosion from the Sunny Point Munitions plant.

At the time of the IPEEE, hydrogen tankers were temporarily installed beyond the north side of the switchyard until permanent hydrogen tanks could be installed [Reference 47]. The tankers were analyzed in the IPEEE; however, they have since been removed and permanent tanks have been installed in their place. Per the BSEP UFSAR [Reference 27], the hydrogen tanks

are located outside the protected area where they do not affect plant capability to achieve and/or maintain safe shutdown and will not cause rupture of a high energy line inside the power plant at power. In addition, there have been no changes to the structural integrity of the Class I buildings; therefore, the screening of this hazard remains valid.

In addition, external flooding was screened per Reference 50.

Per the discussion above, the screening of the “other” external events is valid for this application. Furthermore, due to the margin to the risk thresholds as discussed in Section 7.0, the screening of “other” external hazards is judged to not impact the conclusion that the change in risk due to the ILRT extension is “small”.

5.2.9 Defense-In-Depth Impact

Regulatory Guide 1.174, Revision 3 [Reference 4] describes an approach that is acceptable for developing risk-informed applications for a licensing basis change that considers engineering and applies risk insights. One of the considerations included in RG 1.174 is Defense in Depth. Defense in Depth is a safety philosophy that employs successive compensatory measures to provide accidents or mitigate damage if a malfunction, accident, or naturally caused event occurs at a nuclear facility. The following seven considerations will serve to evaluate the proposed licensing basis change for overall impact on Defense in Depth.

1. <u>Preserve a reasonable balance among the layers of defense.</u>

The usage of the risk metrics of LERF, population dose, and conditional containment failure probability collectively ensures the balance between prevention of core damage, prevention of containment failure, and consequence mitigation is preserved. The change in LERF is “small” per RG 1.174, and the change in population dose and CCFP are “small” as defined in this analysis and consistent with NEI 94-01 Revision 3-A.

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

The adequacy of the design feature (the containment boundary subject to Type A testing) is persevered as evidenced by the overall “small” change in risk associated with the Type A test frequency change.

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

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

4. <u>Preserve adequate defense against potential CCFs.</u>

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

test frequency change.

5. Maintain multiple fission product barriers.

Multiple fission product barriers help ensure the risk of the release of fission products to the environment is small. The portion of the containment affected by the Type A test extension is not a completely independent fission product barrier, due to the effect of Containment Accident Pressure on low pressure ECCS NPSH. Risk analysis demonstrates the change in both CDF and LERF is “small” (per Regulatory Guide 1.174) due to the ILRT extension surveillance frequency change, so the intent of this defense in depth consideration is met.

6. Preserve sufficient defense against human errors.

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

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

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

5.3 Sensitivities

5.3.1 Potential Impact from Steel Liner Corrosion Likelihood

A quantitative assessment of the contribution of steel liner corrosion likelihood impact was performed for the risk impact assessment for extended ILRT intervals. As a sensitivity run, the internal event CDF was used to calculate the Class 3b frequency. The impact on the Class 3b frequency due to increases in the ILRT surveillance interval was calculated for steel liner corrosion likelihood using the relationships described in Section 5.2.6. The EPRI Category 3b frequencies for the 3 per 10-year, 10-year, and 15-year ILRT intervals were quantified using the internal events CDF. The change in the LERF, change in CCFP, and change in Annual Dose Rate due to extending the ILRT interval from 3 in 10 years to 1 in 10 years, or to 1 in 15 years are provided in Table 5-24 – Table 5-29. The steel liner corrosion likelihood was increased by a factor of 1000, 10000, and 100000. Except for extreme factors of 10000 and 100000, the results are relatively insensitive to the corrosion likelihood.

Table 5-24 – Steel Liner Corrosion Sensitivity Case: Unit 1 3B Contribution

	3b Frequency (3-per-10 year ILRT)	3b Frequency (1-per-10 year ILRT)	3b Frequency (1-per-15 year ILRT)	LERF Increase (3-per-10 to 1-per-10)	LERF Increase (3-per-10 to 1-per-15)	LERF Increase (1-per-10 to 1-per-15)
Corrosion Likelihood X 1	1.11E-08	4.62E-08	7.14E-08	3.52E-08	6.03E-08	2.52E-08
Corrosion Likelihood X 1000	1.12E-08	4.91E-08	8.17E-08	3.79E-08	7.05E-08	3.26E-08
Corrosion Likelihood X 10000	1.23E-08	7.52E-08	1.75E-07	6.29E-08	1.62E-07	9.96E-08
Corrosion Likelihood X 100000	2.31E-08	3.36E-07	1.11E-06	3.13E-07	1.08E-06	7.69E-07

Table 5-25 – Steel Liner Corrosion Sensitivity Case: Unit 2 3B Contribution

	3b Frequency (3-per-10 year ILRT)	3b Frequency (1-per-10 year ILRT)	3b Frequency (1-per-15 year ILRT)	LERF Increase (3-per-10 to 1-per-10)	LERF Increase (3-per-10 to 1-per-15)	LERF Increase (1-per-10 to 1-per-15)
Corrosion Likelihood X 1	1.03E-08	4.34E-08	6.70E-08	3.31E-08	5.67E-08	2.36E-08
Corrosion Likelihood X 1000	1.04E-08	4.61E-08	7.67E-08	3.57E-08	6.63E-08	3.06E-08
Corrosion Likelihood X 10000	1.14E-08	7.05E-08	1.64E-07	5.91E-08	1.53E-07	9.34E-08
Corrosion Likelihood X 100000	2.16E-08	3.15E-07	1.04E-06	2.93E-07	1.02E-06	7.22E-07

Table 5-26 – Steel Liner Corrosion Sensitivity: Unit 1 CCFP

	CCFP (3-per-10 year ILRT)	CCFP (1-per-10 year ILRT)	CCFP (1-per-15 year ILRT)	CCFP Increase (3-per-10 to 1-per-10)	CCFP Increase (3-per-10 to 1-per-15)	CCFP Increase (1-per-10 to 1-per-15)
Corrosion Likelihood X 1	5.70E-01	5.77E-01	5.82E-01	7.03E-03	1.21E-02	5.03E-03
Corrosion Likelihood X 1000	5.70E-01	5.77E-01	5.83E-01	7.11E-03	1.22E-02	5.09E-03
Corrosion Likelihood X 10000	5.71E-01	5.78E-01	5.84E-01	7.80E-03	1.34E-02	5.58E-03
Corrosion Likelihood X 100000	5.73E-01	5.87E-01	5.98E-01	1.47E-02	2.52E-02	1.05E-02

Table 5-27 – Steel Liner Corrosion Sensitivity: Unit 2 CCFP

	CCFP (3-per-10 year ILRT)	CCFP (1-per-10 year ILRT)	CCFP (1-per-15 year ILRT)	CCFP Increase (3-per-10 to 1-per-10)	CCFP Increase (3-per-10 to 1-per-15)	CCFP Increase (1-per-10 to 1-per-15)
Corrosion Likelihood X 1	5.70E-01	5.77E-01	5.82E-01	7.08E-03	1.21E-02	5.05E-03
Corrosion Likelihood X 1000	5.70E-01	5.77E-01	5.83E-01	7.16E-03	1.23E-02	5.11E-03
Corrosion Likelihood X 10000	5.71E-01	5.78E-01	5.84E-01	7.85E-03	1.35E-02	5.60E-03
Corrosion Likelihood X 100000	5.73E-01	5.88E-01	5.98E-01	1.48E-02	2.54E-02	1.06E-02

Table 5-28 – Steel Liner Corrosion Sensitivity: Unit 1 Dose Rate

	Dose Rate (3-per-10 year ILRT)	Dose Rate (1-per-10 year ILRT)	Dose Rate (1-per-15 year ILRT)	Dose Rate Increase (3-per-10 to 1-per-10)	Dose Rate Increase (3-per-10 to 1-per-15)	Dose Rate Increase (1-per-10 to 1-per-15)
Corrosion Likelihood X 1	7.27E-04	3.04E-03	4.69E-03	2.31E-03	3.97E-03	1.65E-03
Corrosion Likelihood X 1000	7.35E-04	3.23E-03	5.37E-03	2.50E-03	4.64E-03	2.14E-03
Corrosion Likelihood X 10000	8.07E-04	4.94E-03	1.15E-02	4.14E-03	1.07E-02	6.55E-03

Table 5-28 – Steel Liner Corrosion Sensitivity: Unit 1 Dose Rate

	Dose Rate (3-per-10 year ILRT)	Dose Rate (1-per-10 year ILRT)	Dose Rate (1-per-15 year ILRT)	Dose Rate Increase (3-per-10 to 1-per-10)	Dose Rate Increase (3-per-10 to 1-per-15)	Dose Rate Increase (1-per-10 to 1-per-15)
Corrosion Likelihood X 100000	1.52E-03	2.21E-02	7.27E-02	2.06E-02	7.11E-02	5.06E-02

Table 5-29 – Steel Liner Corrosion Sensitivity: Unit 2 Dose Rate

	Dose Rate (3-per-10 year ILRT)	Dose Rate (1-per-10 year ILRT)	Dose Rate (1-per-15 year ILRT)	Dose Rate Increase (3-per-10 to 1-per-10)	Dose Rate Increase (3-per-10 to 1-per-15)	Dose Rate Increase (1-per-10 to 1-per-15)
Corrosion Likelihood X 1	6.78E-04	2.85E-03	4.41E-03	2.17E-03	3.73E-03	1.55E-03
Corrosion Likelihood X 1000	6.85E-04	3.03E-03	5.04E-03	2.35E-03	4.36E-03	2.01E-03
Corrosion Likelihood X 10000	7.52E-04	4.64E-03	1.08E-02	3.89E-03	1.00E-02	6.14E-03
Corrosion Likelihood X 100000	1.42E-03	2.07E-02	6.82E-02	1.93E-02	6.68E-02	4.75E-02

5.3.2 Expert Elicitation Sensitivity

Another sensitivity case on the impacts of assumptions regarding pre-existing containment defect or flaw probabilities of occurrence and magnitude, or size of the flaw, is performed as described in Reference 24. In this sensitivity case, an expert elicitation was conducted to develop probabilities for pre-existing containment defects that would be detected by the ILRT only based on the historical testing data.

Using the expert knowledge, this information was extrapolated into a probability-versus-magnitude relationship for pre-existing containment defects [Reference 24]. The failure mechanism analysis also used the historical ILRT data augmented with expert judgment to develop the results. Details of the expert elicitation process and results are contained in Reference 24. The expert elicitation process has the advantage of considering the available data for small leakage events, which have occurred in the data, and extrapolate those events and probabilities of occurrence to the potential for large magnitude leakage events.

The expert elicitation results are used to develop sensitivity cases for the risk impact assessment. Employing the results requires the application of the ILRT interval methodology using the expert elicitation to change the probability of pre-existing leakage in the containment.

The baseline assessment uses the Jeffreys non-informative prior and the expert elicitation sensitivity study uses the results of the expert elicitation. In addition, given the relationship between leakage magnitude and probability, larger leakage that is more representative of large early release frequency, can be reflected. For the purposes of this sensitivity, the same leakage

magnitudes that are used in the basic methodology (i.e., 10 L_a for small and 100 L_a for large) are used here. Table 5-30 presents the magnitudes and probabilities associated with the Jeffreys non-informative prior and the expert elicitation used in the base methodology and this sensitivity case.

Table 5-30 – BSEP Summary of ILRT Extension Using Expert Elicitation Values (from Reference 24)

Leakage Size (L_a)	Expert Elicitation Mean Probability of Occurrence	Percent Reduction
10	3.88E-03	86%
100	2.47E-04	91%

Taking the baseline analysis and using the values provided in Table 5-7 – Table 5-14 for the expert elicitation sensitivity yields the results in Table 5-31 and Table 5-32.

Table 5-31 – Unit 1 BSEP Summary of ILRT Extension Using Expert Elicitation Values

Accident Class	ILRT Interval							
	3 per 10 Years				1 per 10 Years		1 per 15 Years	
	Base Frequency	Adjusted Base Frequency	Dose (person-rem)	Dose Rate (person-rem/yr)	Frequency	Dose Rate (person-rem/yr)	Frequency	Dose Rate (person-rem/yr)
1	2.16E-06	2.14E-06	6.58E+02	1.41E-03	2.08E-06	1.37E-03	2.04E-06	1.34E-03
2	5.98E-08	5.98E-08	7.40E+05	4.42E-02	5.98E-08	4.42E-02	5.98E-08	4.42E-02
3a	N/A	1.87E-08	6.58E+03	1.23E-04	6.24E-08	4.10E-04	9.35E-08	6.15E-04
3b	N/A	1.19E-09	6.58E+04	7.83E-05	1.33E-08	8.77E-04	2.20E-08	1.45E-03
4-6	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
7	2.78E-06	2.78E-06	8.49E+06	2.36E+01	2.78E-06	2.36E+01	2.78E-06	2.36E+01
8	4.55E-10	4.55E-10	4.86E+05	2.21E-04	4.55E-10	2.21E-04	4.55E-10	2.21E-04
Totals	5.00E-06	5.00E-06	9.79E+06	2.37E+01	5.00E-06	2.37E+01	5.00E-06	2.37E+01
ΔLERF (3 per 10 yrs base)	N/A				1.21E-08		2.09E-08	
ΔLERF (1 per 10 yrs base)	N/A				N/A		8.70E-09	
CCFP	56.83%				57.08%		57.25%	

Table 5-32 – Unit 2 BSEP Summary of ILRT Extension Using Expert Elicitation Values

Accident Class	ILRT Interval							
	3 per 10 Years				1 per 10 Years		1 per 15 Years	
	Base Frequency	Adjusted Base Frequency	Dose (person-rem)	Dose Rate (person-rem/yr)	Frequency	Dose Rate (person-rem/yr)	Frequency	Dose Rate (person-rem/yr)
1	2.02E-06	2.00E-06	6.58E+02	1.31E-03	1.95E-06	1.28E-03	1.91E-06	1.26E-03
2	4.85E-08	4.85E-08	7.40E+05	3.59E-02	4.85E-08	3.59E-02	4.85E-08	3.59E-02
3a	N/A	1.74E-08	6.58E+03	1.15E-04	5.81E-08	3.82E-04	8.72E-08	5.74E-04
3b	N/A	1.11E-09	6.58E+04	7.30E-05	1.27E-08	8.36E-04	2.10E-08	1.38E-03
4-6	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
7	2.60E-06	2.60E-06	8.49E+06	2.21E+01	2.60E-06	2.21E+01	2.60E-06	2.21E+01
8	4.76E-10	4.76E-10	4.86E+05	2.31E-04	4.76E-10	2.31E-04	4.76E-10	2.31E-04
Totals	4.67E-06	4.67E-06	9.79E+06	2.22E+01	4.67E-06	2.22E+01	4.67E-06	2.22E+01
ΔLERF (3 per 10 yrs base)	N/A				1.16E-08		1.99E-08	
ΔLERF (1 per 10 yrs base)	N/A				N/A		8.26E-09	
CCFP	56.83%				57.08%		57.26%	

The results illustrate how the expert elicitation reduces the overall change in LERF and the overall results are more favorable with regard to the change in risk.

6.0 RESULTS

The results from this ILRT extension risk assessment for BSEP are summarized in Table 6-1 for Unit 1 and Table 6-2 for Unit 2. Table 6-1 and Table 6-2 include the results of the CAP analysis performed in Section 5.2.7. The ΔCDF of 1.61E-08/year for Unit 1 and ΔCDF of 1.54E-08/year for Unit 2 is added to the Class 3b frequency for the 1 in 15 years case. Similarly, the ΔCDF of 9.37E-09/year for Unit 1 and ΔCDF of 9.01E-09/year for Unit 2 is added to the Class 3b frequency for the 1 in 10 years case. The results of the ILRT extension analysis without the inclusion of the CAP analysis results are shown in Sections 5.2.3, 5.2.4, and 5.2.5.

Table 6-1 – Unit 1 ILRT Extension Summary

Class	Dose (person-rem) [Table 5-8]	Base Case 3 in 10 Years [Table 5-6]		Extend to 1 in 10 Years		Extend to 1 in 15 Years	
		CDF/Year	Person-Rem/Year	CDF/Year	Person-Rem/Year	CDF/Year	Person-Rem/Year
1	6.58E+02	2.10E-06	1.38E-03	1.97E-06	1.29E-03	1.87E-06	1.23E-03
2	7.40E+05	5.98E-08	4.42E-02	5.98E-08	4.42E-02	5.98E-08	4.42E-02
3a	6.58E+03	4.44E-08	2.92E-04	1.48E-07	9.74E-04	2.22E-07	1.46E-03
3b	6.58E+04	1.11E-08	7.27E-04	4.62E-08	3.04E-03	7.14E-08	4.69E-03
4-6	ε[1]	ε[1]	ε[1]	ε[1]	ε[1]	ε[1]	ε[1]
7	8.49E+06	2.78E-06	2.36E+01	2.78E-06	2.36E+01	2.78E-06	2.36E+01
8	4.86E+05	4.55E-10	2.21E-04	4.55E-10	2.21E-04	4.55E-10	2.21E-04
Total		5.00E-06	2.37E+01	5.00E-06	2.37E+01	5.00E-06	2.37E+01

ILRT Dose Rate from 3a and 3b				
ΔTotal Dose Rate	From 3 Years	N/A	2.90E-03	4.98E-03
	From 10 Years	N/A	N/A	2.08E-03
%ΔDose Rate	From 3 Years	N/A	0.012%	0.021%
	From 10 Years	N/A	N/A	0.009%
3b Frequency (LERF)				
ΔLERF	From 3 Years	N/A	3.52E-08	6.03E-08
	From 10 Years	N/A	N/A	2.52E-08
CCFP %				
ΔCCFP%	From 3 Years	N/A	0.703%	1.206%
	From 10 Years	N/A	N/A	0.503%

1. ε represents a probabilistically insignificant value or a Class that is unaffected by the Type A ILRT.

Table 6-2 – Unit 2 ILRT Extension Summary

Class	Dose (person-rem) [Table 5-8]	Base Case 3 in 10 Years [Table 5-6]		Extend to 1 in 10 Years		Extend to 1 in 15 Years	
		CDF/Year	Person-Rem/Year	CDF/Year	Person-Rem/Year	CDF/Year	Person-Rem/Year
1	6.58E+02	1.97E-06	1.29E-03	1.84E-06	1.21E-03	1.74E-06	1.15E-03
2	7.40E+05	4.85E-08	3.59E-02	4.85E-08	3.59E-02	4.85E-08	3.59E-02
3a	6.58E+03	4.14E-08	2.72E-04	1.38E-07	9.08E-04	2.07E-07	1.36E-03
3b	6.58E+04	1.03E-08	6.78E-04	4.34E-08	2.85E-03	6.70E-08	4.40E-03
4-6	ε[1]	ε[1]	ε[1]	ε[1]	ε[1]	ε[1]	ε[1]
7	8.49E+06	2.60E-06	2.21E+01	2.60E-06	2.21E+01	2.60E-06	2.21E+01
8	4.86E+05	4.76E-10	2.31E-04	4.76E-10	2.31E-04	4.76E-10	2.31E-04
Total		4.67E-06	2.22E+01	4.67E-06	2.22E+01	4.67E-06	2.22E+01
ILRT Dose Rate from 3a and 3b							
ΔTotal Dose Rate	From 3 Years	N/A		2.73E-03		4.67E-03	
	From 10 Years	N/A		N/A		1.95E-03	
%ΔDose Rate	From 3 Years	N/A		0.012%		0.021%	
	From 10 Years	N/A		N/A		0.009%	
3b Frequency (LERF)							
ΔLERF	From 3 Years	N/A		3.31E-08		5.67E-08	
	From 10 Years	N/A		N/A		2.36E-08	
CCFP %							
ΔCCFP%	From 3 Years	N/A		0.708%		1.213%	
	From 10 Years	N/A		N/A		0.505%	

1. ε represents a probabilistically insignificant value or a Class that is unaffected by the Type A ILRT.

7.0 CONCLUSIONS AND RECOMMENDATIONS

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

- Regulatory Guide 1.174 [Reference 4] provides guidance for determining the risk impact of plant-specific changes to the licensing basis. Regulatory Guide 1.174 defines very small changes in risk as resulting in increases of CDF less than 1.0E-06/year. Since BSEP relies on containment accident pressure for ECCS NPSH during certain design basis accidents, extending the ILRT interval may impact CDF. The BSEP PRA model was used to estimate the potential change in CDF if containment accident pressure was unavailable due to a pre-existing containment leak. The containment accident pressure analysis performed in Section 5.2.7 estimates the potential increase in the overall CDF to be 1.61E-08 for Unit 1 and 1.54E-08 for Unit 2, which are “very small” using the acceptance guidelines of Regulatory Guide 1.174 [Reference 4].
- When external event risk is included, the increase in CDF resulting from a change in the Type A ILRT test interval from 3 in 10 years to 1 in 15 years is estimated as 1.10E-07/year for Units 1 and 2 using the EPRI guidance per Table 5-20 and Table 5-21. As such, the estimated change in CDF is determined to be “very small” using the acceptance guidelines of Regulatory Guide 1.174 [Reference 4]. The risk change resulting from a change in the Type A ILRT test interval from 3 in 10 years to 1 in 15 years bounds the 1 in 10 years to 1 in 15 years risk change.
- Regulatory Guide 1.174 [Reference 4] provides guidance for determining the risk impact of plant-specific changes to the licensing basis. Regulatory Guide 1.174 defines very small changes in risk as resulting increases in LERF less than 1.0E-07/year. The increase in LERF resulting from a change in the Type A ILRT test interval from 3 in 10 years to 1 in 15 years is estimated as 6.03E-08/year for Unit 1 and 5.67E-08/year for Unit 2 using the EPRI guidance; this value increases negligibly if the risk impact of corrosion-induced leakage of the steel liners occurring and going undetected during the extended test interval is included. As such, the estimated change in LERF is determined to be “very small” using the acceptance guidelines of Regulatory Guide 1.174 [Reference 4].
- When external event risk is included, the increase in LERF resulting from a change in the Type A ILRT test interval from 3 in 10 years to 1 in 15 years is estimated as 4.05E-07/year for Unit 1 and 4.33E-07/year for Unit 2 using the EPRI guidance, and total LERF is 5.55E-06/year for Unit 1 and 5.53E-06/year for Unit 2. As such, the estimated change in LERF is determined to be “small” using the acceptance guidelines of Regulatory Guide 1.174 [Reference 4]. The risk change resulting from a change in the Type A ILRT test interval from 3 in 10 years to 1 in 15 years bounds the 1 in 10 years to 1 in 15 years risk change.
- The effect resulting from changing the Type A test frequency to 1-per-15 years, measured as an increase to the total integrated plant risk for those accident sequences influenced by Type A testing, is 4.98E-03 person-rem/year for Unit 1 and 4.67E-03 person-rem/year for Unit 2. NEI 94-01 [Reference 1] states that a small population dose is defined as an increase of ≤ 1.0 person-rem per year, or ≤ 1% of the total population dose, whichever is less restrictive for the risk impact assessment of the extended ILRT intervals. The results of this calculation meet these criteria. Moreover, the risk impact for the ILRT extension when compared to other severe accident risks is negligible.

- The increase in the conditional containment failure probability from the 3 in 10 years interval to 1 in 15 years interval is 1.206% for Unit 1 and 1.213% for Unit 2. NEI 94-01 [Reference 1] states that increases in CCFP of ≤ 1.5% is small. Therefore, this increase is judged to be small.

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

Previous Assessments

The NRC in NUREG-1493 [Reference 6] has previously concluded that:

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

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

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

A. APPENDIX A: PRA ACCEPTABILITY

A.1. Internal Events PRA Quality Statement for Permanent 15-Year ILRT Extension

The BSEP internal events PRA model (MOR16) is used to calculate CDF and LERF for the permanent 15-year ILRT extension. Any elements of the supporting requirements detailed in ASME/ANS RA-Sa-2009 [Reference 41] that could be significantly affected by the application are required to meet Capability Category II requirements.

The BSEP Units 1 and 2 Internal Events and Internal Flooding PRA Peer Review was performed April 2010 using the NEI 05-04 process [Reference 45], the ASME PRA Standard [Reference 41] and Regulatory Guide 1.200, Rev. 2 [Reference 43]. The purpose of this review was to establish the acceptability of the PRA for the spectrum of potential risk-informed plant licensing applications for which the PRA may be used. The 2010 BSEP PRA Peer Review was a full-scope review of the Technical Elements of the Internal Events and Internal Flooding, at-power PRA. A focused scope peer review of the Internal Flood model was conducted in December 2016, which covered 28 SRs.

The ASME PRA Standard has 325 individual SRs; 322 Supporting Requirements are applicable to the BSEP PRA. Three (3) of the ASME/ANS PRA Standard Supporting Requirements are not applicable to BSEP (e.g., PWR-related, linked event tree methodology-related). Of the 322 ASME/ANS PRA Standard Supporting Requirements applicable to BSEP, approximately 88% are supportive of Capability Category II or greater. Of the 79 unique Facts and Observations (F&Os) generated by the Peer Review Team, 44 were considered peer review Findings and 35 were Suggestions.

Table A.1-1 – BSEP Internal Events PRA Assessment

Capability Categories	# SRs	% Total SRs
Not Met (I, II, or III)	28	8.6%
I	10	3.1%
I/II	14	4.3%
II	37	11.4%
II/III	21	6.5%
III	3	0.9%
Met (All)	209	64.3%
Not Applicable	3	1.9%
Total	325	100%

An F&O closure technical review was conducted in August 2017 and most, but not all, open F&Os were reviewed for closure. Following the F&O closure, 15 Internal Event and Internal Flooding F&Os remain open; these F&Os are dispositioned in Section A.1.1 for their impact on the ILRT extension. All the Finding Level F&Os have been determined to not significantly affect the ILRT extension analysis.

A.1.1 Disposition of Open Internal Events PRA Open Findings and Observations (F&Os)

The following table provides the remaining open Internal Events and Internal Flood F&Os following the peer reviews and F&O closure.

Finding Number	Supporting Requirement(s)	Capability Category (CC)	Description	Disposition for ILRT Extension
1-11 **Internal Events**	SC-B3	I/II/III	For small break LOCA, the high end of water break is approximately 1" dia., RCIC is credited for HPI for success, but no MAAP run was performed to demonstrate the success.	No changes have been made to the model in response to this F&O. A specific MAAP analysis was performed in BNP-PSA-076 [Reference 39] to confirm that RCIC is a success path for a 1-inch diameter break. This is a documentation issue and does not impact the ILRT extension application.
1-19 **Internal Events**	LE-E1	I/II/III	Parameter values were selected with regards to the PRA Standard's requirements for HR and DA. Consideration of severe accident conditions upon these parameters is provided in Appendix M, or in some instances Appendix C, of the BNP-PSA-049 notebook. Section G of LE notebook captures the human error modeling, and incorporated the general methodology approach used in Level 1 HRA. However, the data values documented in BNP-PSA-049 were developed during a previous PRA update. It appears that some values may need to be updated to be consistent with changes in the Level 1 data. For example, OSP recovery values (such as ACP1XHE-MN-OFFE) are not consistent with the current OSP recovery curve (and LOSP is now categorized by type of OSP failure as opposed to a composite value). On the other hand, changes in component failure data appear to have been updated in the Level 2 trees. However, the documentation does not indicate that the values shown in BNP-PSA-049 have been superseded.	This Finding was assessed by the F&O Closure team as partially closed, requiring only documentation updates. Therefore, there is no impact on the ILRT extension.

Finding Number	Supporting Requirement(s)	Capability Category (CC)	Description	Disposition for ILRT Extension
3-3 **Internal Events**	HR-E3	I	Operator interview insights are documented in the HRA Calculator. The information contained in the HRA Calculator was sufficient to demonstrate that Capability Category I was met. However, the information in the HRA did not demonstrate that detailed talk throughs with Operations and Training Personnel were conducted for the purpose of confirming procedure interpretations. For example, many of the calculations referred only to an interview conducted with a single operator on 9/16-17/2008. A few calculations referred a "talk through" in January 2008, an operator interview on 3/11/2010, or simulator runs conducted on 1/19/2010. A few calculations (OPER-BLACKSTART, OPER-CNS, OPER-CWSIE) did not have any input on operator interviews. The purpose and content of these interviews is not evident.	As a resolution to this finding the following was performed: • Detailed operator interviews were conducted for the purpose of confirming procedure interpretations. PRA documents have been updated to improve their clarity in this area. • The HFEs mentioned are no longer used in the PRA. • A generic operator discussion sheet was added to the BSEP HRA calculation. • Operator interviews were stated where applicable in the HRA calculator. If there were any special comments from the operator, they were included in the operator response tab for each operator action. Since this SR already meets CCI, this finding simply represents an opportunity for enhancement to the documentation, and does not impact the ILRT extension.
3-4 **Internal Events**	HR-E4	I	While it was documented that simulator observations and talk-throughs were performed in most HRA calculations, there is no evidence that these observations or talk-throughs were used to confirm the response models for the scenarios modeled in the PRA. For example, there was no interview checklist, simulator/scenario checklist, or other documentation to demonstrate that the HRA analyst confirmed the response models.	As a resolution to this finding the HRA documentation has been updated to reference applicable simulator runs, operator interviews, and checklists. This SR meets CCI and is a document enhancement issue only. This finding does not impact the ILRT extension.

Finding Number	Supporting Requirement(s)	Capability Category (CC)	Description	Disposition for ILRT Extension
3-6 **Internal Events**	HR-G3	I/II/III	In general, the HRA calculator file was reviewed and found to provide an assessment of the performance shaping factors listed in the SR for the HEP calculations. Some detail in the calculations could be enhanced. For example, the operator action OPER-LDSHD calculation does not have the cognitive procedure listed and does not address the training requirements. Calculations for OPERMSIVCBP and OPER-DEPRESS1 state that simulator and classroom training are provided but does not provide a frequency. The calculations for OPER-DCDG and OPER-N2SUPPLY do not address training, the cognitive procedure or the staffing requirements. Problems were noted with the HRA calculation for OPER-DCDG. Specifically, no execution failure probabilities were assigned to the tasks of starting and connecting the DG. Additionally, the calculation may not have considered all of the necessary breaker manipulations.	This Finding was assessed by the F&O Closure team as partially closed, requiring only documentation updates. Therefore, there is no impact on the ILRT extension.

Finding Number	Supporting Requirement(s)	Capability Category (CC)	Description	Disposition for ILRT Extension
3-9 **Internal Events**	QU-C2	I/II/III	Dependency analysis was performed on the identified HFE combinations (see BNP-PSA-034 and associated spreadsheets). The dependency assessment approach used appears to be appropriate. In developing recovery rules to be applied to the cutsets, maximum combinations of 3 HFEs were included. Any cutsets with greater than three HFEs that meet the recovery rule criteria are recovered to a minimum joint HFE of 1E-06 (and often higher). As a result, there are cutsets that contain more than three HFEs that are being recovered to a higher frequency than may be warranted (either because one or more of the additional HFEs may be independent of the others, or because the joint HFE probability is still above the floor value of 1E-06 (and often higher). As a result, there are cutsets that contain more than three HFEs that are being recovered to a higher frequency than may be warranted (either because one or more of the additional HFEs may be independent of the others, or because the joint HFE probability is still above the floor value of 1E-06 and hence could be reduced further). This conservatism appears to increase the calculated CDF/LERF by at least a modest amount.	BNP-PSA-034 (Revision 17), Brunswick Nuclear Plant PRA – Human Reliability Analysis, Section 7.1.5, discusses that dependence between any two or more human failure events that appear in the same cut set were manually examined. Table 9 lists the individual HEPs. Table 10 lists the Summary of Combinations of Post-Initiator, Procedure-Driven (Type CP) HFEs. The highest order dependency event in Table 10 includes several cutsets with 4 HEPs. However, in examining the top 95% cutsets, there were some cutsets with 5 and 6 HEP events that were not explicitly analyzed for dependencies. But with the use of a minimum combination HEP value, there would be little to no change to the current recovery values when adding those additional HEPs to the dependency analysis. The larger bulk of dependencies addressed have produced an HRA with realistic results and would not be notably affected by applying additional dependency recoveries that exist in low significant cutsets, and therefore have no impact on the ILRT extension.

Finding Number	Supporting Requirement(s)	Capability Category (CC)	Description	Disposition for ILRT Extension
3-11 **Internal Events**	LE-C10 LE-C12	I	There is no evidence that significant accident sequences were reviewed to determine if engineering analyses could support continued equipment operation or operator actions to reduce LERF. It was noted that this conservative approach with respect to equipment survivability was documented in the uncertainty analysis (BNP-PSA-075, Table 1, Item 236).	No credit for equipment survivability or human actions in adverse environments is taken in the BSEP LERF model that would satisfy SR LE-C10 or LE-C12. While there may be some conservatism in the LERF model, credit for equipment survivability or operator actions in adverse environments is not expected to significantly impact the baseline LERF. A reduction in the baseline LERF would lead to an increase in the calculated delta LERF for the ILRT analysis, but a decrease in calculated total LERF. Per section 7.0, the calculated delta LERF is well below the threshold for a change in LERF to be considered small, so if the baseline LERF were not drastically reduced, the impact to the ILRT extension analysis would be minimal.
3-12 **Internal Events**	LE-C3	I	As discussed in BNP-PSA-049, Appendix D, Section D.1, the CET structure allows for the identification of recovery and repair actions that can terminate or mitigate the progression of a severe accident. This process was incorporated into the original analysis, rather than performing a review of significant accident progression sequences and then incorporating repair, as would be inferred from the standard. However, it does not appear that significant accident progression sequences were reviewed.	The BSEP LERF model includes two operator recovery actions for cases of instrumentation or control problems as a part of the original analysis. These recovery actions consider plant conditions for feasibility, as well as use bounding repair rates for instrumentation repairs in the exponential failure model. This treatment is consistent with the repair justification requirements of CCII for SR LE-C3. Because these actions were incorporated in the original analysis, this SR is met at CCI. If a full review of significant accident progression sequences for equipment repair was performed, credit would be minimal and would not have a significant impact on risk results. Therefore, there is no impact on the ILRT extension.

Finding Number	Supporting Requirement(s)	Capability Category (CC)	Description	Disposition for ILRT Extension
3-13 **Internal Events**	LE-C13	I	BNP-PSA-049, Section 3.1.2 notes that the treatment of scrubbing by the reactor building is treated in a conservative method. This conservative approach was identified in the uncertainty analysis (BNP-PSA-075, Table 1, Item 217).	The BSEP LERF model does not provide any credit for scrubbing in the reactor building, and therefore is treated in a conservative manner consistent with CCI. This lack of scrubbing credit does not affect the CDF results. Including a scrubbing credit to applicable LERF scenarios would result in some level of reduction in the overall baseline LERF, though the impact is not expected to be significant. A reduction in the baseline LERF would lead to an increase in the calculated delta LERF for the ILRT analysis, but a decrease in calculated total LERF. Per section 7.0, the calculated delta LERF is well below the threshold for a change in LERF to be considered small, so if the baseline LERF were not drastically reduced the impact to the ILRT extension analysis would be minimal.

Finding Number	Supporting Requirement(s)	Capability Category (CC)	Description	Disposition for ILRT Extension
IFSN-A8-1 **Internal Flood**	IFSN-A8	I	From IFSO-A4, the effects of gaskets and expansion joint failures were not propagated beyond failing the attached equipment. Section F.4.8 discusses the propagation between rooms, and basis for drain paths. No propagation from gaskets or expansion joints was modeled.	The CDF and LERF contributions from gasket and expansion joint failures, including effects from propagation, have been included in the internal flooding models. BSEP IFPRA calculations contain the listing of expansion joints and gaskets along with their failure rates. The component failures have been mapped to the associated initiating events in the model. New scenarios and their propagation impacts based on similar pipes in the flood zone have been developed and assessed for the expansion joint and gasket flooding scenarios. The F&O was partially closed per the closure review as the circulating water expansion joints were not addressed. The circulating expansion joints are not risk significant to the BSEP IFPRA risk as circulating water piping does not contribute a significant amount to CDF/LERF and circulating water expansion joint ruptures represent a small portion of the total rupture frequency for IFPRA. The SR is met at CCI and the issue will not have significant impact on the CDF/LERF; therefore, the F&O does not impact the ILRT extension risk metrics.

Finding Number	Supporting Requirement(s)	Capability Category (CC)	Description	Disposition for ILRT Extension
IFSO-B2-1 **Internal Flood**	IFSO-B2	II	The IFSO-A section lacks documentation on several modeling requirements that are shown to be correct through investigation. • In IFSO-A1, no drain backflow propagation identification provided in the documentation. Investigation shows that drains flow to an exterior rad waste building floor drain collection tank from all locations which would justify the assumption in [BNP-PSA-035 Section] F.1.3; however there is no discussion, drawings, or justification provided in the analysis for screening • In IFSO-A1 there is little to no documentation of doors and door failures contributing to propagation and critical height determination. • Capacity of the sources per IFSO-A5 is not documented, it was identified this information is in the flooding database but it is not discussed in the flooding calculation.	This F&O is associated with multiple documentation issues. • The system diagrams and system description for the Liquid Radwaste System were collected, reviewed, and documented in the IFPRA calculation as described in the response to IFSN-B2. The floor drain flow to the Radwaste Building and the conclusion that drain backflow is not a flooding concern in the other buildings was verified. F&O IFSN-B2-1 was closed out through F&O closure review. • The documentation of door failure critical height determination has been included per the response to IFSN-A2. F&O IFSN-A15-1 was closed out through F&O closure review. • A list of all potential flood sources was updated and documented as described in the response to IFSN-A15. The capacities of those systems retained for further assessment are included in the updated documentation and were compared to the capacities from the database table used in the flooding propagation analysis. Capacities used for all sources in the original propagation analysis bounded the capacities for all systems described in the response to IFSN-A15. F&O IFSN-A15-1 was closed out through F&O closure review. These are documentation issues only and the associated technical F&Os have been closed out through a closure review. Therefore, there is no impact on the ILRT extension.

Finding Number	Supporting Requirement(s)	Capability Category (CC)	Description	Disposition for ILRT Extension
IFEV-A5-1 **Internal Flood**	IFEV-A5	Not Met	New Methodology was applied to use pipe length and flood and major flood frequency based on diameter and flow rate. The analysis should have evaluated flood frequency for small pipe and flows, and Flood frequency AND Major Flood frequency for large pipe and flows. However, the analysis only applied major flood frequencies to large pipe, omitting flood frequency from large pipe which is the dominant frequency. Table F.15 provides the different frequencies from the EPRI Tech Report, but they are applied incorrectly in the analysis as shown in Table F.16.	The existing flood scenario frequencies have mostly been adjusted to include both the Electric Power Research Institute (EPRI) Flood and Major Flood initiating event frequencies. Table F.15 of the internal flooding calculation provides a mapping of piping frequencies and their associated system designation. The updated EPRI values are from TR 3002000079. Since the flooding frequency data in the calculation and the EPRI data have different pipe size breakpoints, the pipe size intervals were adjusted to match. The corresponding frequencies were then adjusted by the ratio of new EPRI flood and major flood frequency to existing major flood frequency. The appropriate multiplier was then applied to each scenario based on pipe size and fluid system type. This assumes all floods are Major Floods that bound both Flood and Major Flood frequency contributions. Therefore, this open F&O would not affect results in a manner that would significantly impact the ILRT extension application.

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Finding Number	Supporting Requirement(s)	Capability Category (CC)	Description	Disposition for ILRT Extension
IFQU-A5-1 **Internal Flood**	IFQU-A5	Not Met	The operator action referred to in the resolution for mitigation of SW floods and the XOPER_F25 HFE satisfy approved HRA methodology. The assumed screening value for HFE XOPER_F60 (1E-3/XOPER_F25) is still credited in the analysis and satisfies the condition specified in the ASME PRA Standard for a significant event with regard to the FV importance measure.	A scenario-specific human error probability (HEP) that meets the requirements of the Standard was developed (i.e., see response to F&Os IFSN-A3 and IFQU-A6) and included in the updated model and quantification. The guidance in SR HR-F1 of Section 2-2.5 of the Standard for developing human failure events (HFEs) was followed, and the HRA Calculator, v5.1, which meets the requirements of the Standard, was used. An operator interview was conducted on February 6, 2017, to validate the procedures and assumptions used as the basis for the modeling. All assumptions and bases for the performance shaping factors (PSFs) were documented in the HRA Calculator. Dependency analysis was considered for both CDF and LERF in regard to the new flooding operator action, and documentation of dependency levels has been included in the assessment. The accident sequences were assessed in the cutset review, and descriptions of the top cutsets were included in the documentation. Detailed modeling of XOPER_F60 yields a human error probability lower than the one previously used (combination human error probability of 1E-03 (XOPER_F25 and XOPER_F60)). Therefore, the current analysis is conservative but does not impact the ILRT extension.
IFQU-A6-1 **Internal Flood**	IFQU-A6	Not Met	See Description of F&O IFQU-A5-1. Apply approved HRA methods to HFE XOPER_F60 to eliminate 1E-3 screening value.	See disposition for F&O IFQU-A5-1.

Finding Number	Supporting Requirement(s)	Capability Category (CC)	Description	Disposition for ILRT Extension
IFQU-B2-1 **Internal Flood**	IFQU-B2	Met I/II/III	The documentation did not justify screening of the flood sources, and did not explain sufficiently the description of cutsets and sequences for dominant floods. There is an inconsistency in documentation between how conventional service water and nuclear service water are identified in the flood analysis, flood database, and PRA model sequences.	Documentation of the processes used to determine the applicable flooding sequences and the quantification of the model has been added in accordance with the requirements of the Standard. The accident sequences/cutsets were reviewed for consistency and correctness, and the sequence-specific HEP that was added was validated. The basis for this documentation F&O included several specific items that have also been addressed individually. The process that describes how flood sources were screened was documented, and the list of potential flood sources retained for further analysis has been updated (i.e., see F&O responses IFSN-A15 and IFSN-A16). The fault trees and initiating event frequencies have been updated based on changes documented in the other F&O responses, and the model has been re-quantified. The detailed descriptions of the cutsets and accident sequences have been added. The Conventional Service Water and Nuclear Service Water modeling has been validated and clarified. The F&O was partially closed per the closure review as unit differences were not properly addressed. Differences were attributed to a variation in the initiating event frequencies used. These frequencies were reviewed and modifications made to ensure both units used the same methodology. These corrections eliminated differences in the results between units. Therefore, there is no impact on the ILRT extension application.

A.2. Fire PRA Quality Statement for Permanent 15-Year ILRT Extension

The BSEP Fire Probabilistic Risk Assessment (FPRA) Peer Review was performed December 2011 using the NEI 07-12 process [Reference 44], the ASME PRA Standard [Reference 41], and Regulatory Guide 1.200, Rev. 2 [Reference 43]. The purpose of this review was to establish the acceptability of the FPRA for the spectrum of potential risk-informed plant licensing applications for which the FPRA may be used. The 2011 BSEP FPRA Peer Review was a full-scope review of all of the technical elements of the BSEP at-power 2011 MOR Fire PRA against all technical elements in Section 4 of the ASME/ANS Combined PRA Standard, including the referenced internal events Supporting Requirements (SRs) in Section 2 of the ASME/ANS Combined PRA Standard [Reference 41].

The Peer Review team consisted of six team members, with extensive qualifications in all areas of FPRA as required by NEI 07-12 [Reference 44]. The team members experience averaged over 20 years in PRA or Fire Protection, with extensive experience in FPRA, the FPRA Section of the Standard, and NUREG/CR-6850.

The Fire PRA Section of the ASME PRA Standard has 182 individual SRs, and references 237 individual SRs in the internal events PRA section of the Standard; the BSEP Peer Review included all of the SRs and all applicable reference SRs (see Table A.2-1). For the assessment of the reviewed ASME PRA Standard SRs, 105 unique Facts and Observations (F&Os) were generated by the Peer Review team, 53 were peer review Findings, 50 were Suggestions, and one was an “Unreviewed Analytical Method.”

Table A.2-2 – BSEP Fire PRA Assessment

Capability Categories	# SRs	% Total SRs	% Assessed SRs
Not Met (I, II, or III)	36	8.6%	13.7%
I	18	4.3%	6.9%
I/II	10	2.4%	3.8%
II	20	4.8%	7.6%
II/III	12	2.9%	4.6%
III	1	0.2%	0.4%
Met (All)	165	39.4%	63.0%
Not Reviewed	0	0.0%	N/A
Not Applicable	156	37.2%	N/A
Total	419	100%	100%

An F&O Finding closure technical review was conducted in July 2017 to review all open Fire PRA F&Os. Following the F&O closure, six F&Os remain open; these F&Os are dispositioned in Section A.2.1 for their impact on the ILRT extension. All the Finding Level F&Os have been determined to not significantly affect the ILRT extension analysis.

A.2.1 Disposition of Open Fire PRA Open Findings and Observations (F&Os)

Finding Number	Supporting Requirement(s)	Capability Category (CC)	Description	Disposition for ILRT Extension
1-34 **Fire**	FSS-G2	Met I/II/III	A screening value for rated barrier probability of 1E-02 was applied. This may not be bounding depending on the features of the barrier (doors, penetrations, dampers).	The peer review team provided a possible resolution of using a screening value of 0.1 in accordance with NUREG/CR-6850. The BSEP fire PRA quantification calculation has been revised to use the screening probability of 0.1 and the screening of HGL Multi Compartment Analysis has been performed in accordance with NUREG/CR-6850. The screening value of 0.1 was used on the exposing compartment to screen out compartments from the MCA analysis. However, the 0.1 barrier failure probability was also inappropriately applied for certain fire compartment combinations where the partitioning element was open (i.e., a barrier failure probability of 1.0 should have been applied). MCA scenarios account for <0.01% of Fire CDF and LERF, so even if the scenario frequency of all MCA scenarios was increased by 10, the fire risk contribution would only be approximately 0.1%. Therefore, there is no more than a minimal impact on the ILRT extension application.

Finding Number	Supporting Requirement(s)	Capability Category (CC)	Description	Disposition for ILRT Extension
1-36 **Fire**	QU-B2 QU-B3 FQ-B1 QU-F2 FQ-F1	NOT MET NOT MET MET I/II/III MET I/II/III MET I/II/III	Truncation in the CDF and LERF was varied, based upon the CCDP/CLERP. For example, CCDP of 1.0 uses a truncation of 1.0, while a CCDP of 1E-03 uses a truncation of 1E-07. Overall, the process using the ones run results in difficultly running FRANC at a very low cutoff. A review of the truncation levels was performed. Hundreds of the sequences have truncation within a factor of 100 or less of the CCDP. Several of these sequences were re-run, and the new CDFs were compared to the original CDFs. Changes in the results vary from about 5% to as much as 25%. Many of the sequences affected are in the top 25 fire sequences. Additionally, a large number of scenarios are listed with zero CCDP. When these were re-run with lower truncation values, cutsets were generated. This can be important for scenarios with higher ignition frequencies.	The truncation approach was changed in Revision 1 of the fire quantification calculation (BNP-PSA-080) in response to this F&O. Scenarios are now run at an effective truncation of 1E-09/yr for CDF and 1E-10/yr for LERF which is more than four orders of magnitude below the resulting CDF and LERF plant totals. A truncation study was added in Revision 3, which demonstrates that the calculated CDF values may be non-conservative as the change with a decade lower truncation exceeds 5% (9% for Unit 1 and 8% for Unit 2). Assuming all of this change in CDF is Class 3b, a LERF increase of 8-9% will not result in the risk metric going above “small” per RG 1.174.

2-22 **Fire**	CF-A1 CF-B1	Met I Met I/II/III	BNP-PSA-080 Section 4.3.4, Fire Induced Spurious Event Probabilities, document the methods used for conditional failure probabilities for fire-induced circuit failures. Circuit Analysis was performed in change package BNP-0137 to determine the probability of a spurious operation for various cables. Risk significant contributors were not identified (quantification was complete later in the process) and utilized thus cannot meet the capability category CC-II. For example, the Unit 1 CDF importance results include the following spurious events for which conditional probabilities have not been developed: HPC1PPS-SA-N12A_TPRESSURE SWITCH E41-N012A SPURIOUSLY ACTUATES HPC1PPS-SA-N12C_TPRESSURE SWITCH E41-N012C SPURIOUSLY ACTUATES RCI1TME-HI-021B_TTEMPERATURE ELEMENT E51-TE-N021B SPURIOUS OPERATION RCI1TME-HI-022B_TTEMPERATURE ELEMENT E51-TE-N022B SPURIOUS OPERATION RCI1PPS-SA-N012A_TPRESSURE SWITCH E51-N012A SPURIOUS OPERATION RCI1PPS-SA-N012C_TPRESSURE SWITCH E51-N012C SPURIOUS OPERATION HPC1PPS-SA-N12B_TPRESSURE SWITCH E41-N012B SPURIOUSLY ACTUATES HPC1PPS-SA-N12D_TPRESSURE SWITCH E41-N012D SPURIOUSLY ACTUATES SRV1SRV-CO-F013G_TNON-ADS SAFETY RELIEF VALVE B21-F013G SPURIOUSLY OPENS RHR1MDP-SA-C002C_TRHR PUMP E11-C002C SPURIOUS START DUE TO FIRE RCI1PPS-SA-N012B_TPRESSURE SWITCH E51-N012B SPURIOUS OPERATION RCI1PPS-SA-N012D_TPRESSURE SWITCH E51-N012D SPURIOUS OPERATION HPC1PPS-SA-N17A_TPRESSURE SWITCH E41-N017A SPURIOUS OPERATION HPC1PPS-SA-N17B_TPRESSURE SWITCH E41-N017B SPURIOUS OPERATION	Spurious cable failures were analyzed, and probabilities were included in the Fire PRA. Conditional failure probabilities were assigned to the most risk significant contributors, causing them to become less risk significant and allowing these less risk significant contributors to appear relatively more risk significant. More could have been done, but the iterative process stopped when satisfactory results were obtained. The current analysis is conservative in that for cases where specific conditional probabilities have not been developed, failure or spurious operation is given a probability of 1.0. Therefore, there is no impact on the ILRT extension.

Finding Number	Supporting Requirement(s)	Capability Category (CC)	Description	Disposition for ILRT Extension
			SWS1PPS-SAP129L_TPRESSURE SWITCH PS129 SPURIOUS OPERATION FAILS LOW ISOLATES SWS1PPS-SAP129L_TPRESSURE SWITCH PS129 SPURIOUS OPERATION FAILS LOW ISOLATES HEADER Note that if the instrument spurious operations above are not caused by a hot short, detailed circuit analysis is likely not needed. However, the valve and pump spurious operation would likely benefit from additional analysis.	
4-1 **Fire**	FSS-A1	NOT MET	The BSEP FPRA calculates using: 1) A severity factor 0.1, where 90% of the fires are contained within the MCC 2) HRR severity factors are treated independently, similar to other cabinets.	In lieu of an accepted generic method at the time, BSEP used the analysis method piloted at HNP, which used a breaching factor of 0.1. However, FAQ 14-0009 has since then been issued and uses a breaching factor of 0.23, slightly more than double the value assumed at BSEP. The contribution from closed MCC scenarios is small (<1% to overall CDF and LERF), so assuming a 1% contribution, doubling the breaching factor will lead to approximately a 1% increase in risk contribution due to closed MCCs. Therefore, impact on the ILRT extension application is minimal.

Finding Number	Supporting Requirement(s)	Capability Category (CC)	Description	Disposition for ILRT Extension
6-4 **Fire**	FSS-G4	MET I	Passive fire barriers with a fire resistance rating are credited in the multicompartment analysis. The failure rates used are those prescribed in NUREG 6850, however, the worst case value for failure probability of the barrier is used.	Walkdowns were performed to gather the targets and barriers between the exposing and exposed compartments. The walkdowns are documented in BNP-PSA-080 Attachment 7; however, only the worst-case barrier failure is noted in Tables 6 and 7. Per Tables 4 and 5 of BNP-PSA-080 Attachment 7, the unscreened MCA scenarios lead to minimal risk increase as most of the MCA scenarios do not increase in CCDP compared to the baseline HGL scenarios. The highest increases in CDF are of 1E-10 magnitude and 1E-12 magnitude for LERF. Non-conservative failure barrier probabilities may also have led to MCA scenarios being inappropriately screened for low scenario frequency. However, for a scenario to be screened due to low barrier failure probability, the fire ignition frequency and other factors must already have led to a low scenario frequency; therefore, an increase in failure probability would have little impact on the total scenario frequency. Furthermore, the CDF/LERF increase due to inappropriately screening applicable MCA scenarios would be minimal; and therefore, there is no impact to the conclusions of the ILRT analysis.

Finding Number	Supporting Requirement(s)	Capability Category (CC)	Description	Disposition for ILRT Extension
6-5 **Fire**	FSS-G2	MET I/II/III	Screening methodology is provided in BNP-PSA-080, Section 6.0. However: the MCA screening did not consider the impact of possible localized effect (e.g., damage to equipment) near penetrations and barriers. In addition, a screening value was used without justification and the cumulative risk for the screened scenarios was not evaluated.	As described in Attachment 7 to BNP-PSA-080, plant walkdowns were performed to identify targets in the exposed compartments near the barriers separating the exposing and exposed compartments. The localized damage in the adjacent compartment near barriers for all compartments that screened out and for compartments where MCA was performed but did not achieve a HGL in the combined compartments was included. The localized targets of the adjacent compartment were added to the HGL evaluation for the exposed compartment. Neither the guidance in NUREG/CR-6850 nor Supporting Requirement FSS-G2 in ASME/ANS RA-Sa-2009 requires an evaluation of the cumulative risk of the screened scenarios to justify the definition of a screening value. There is no impact on the application.

A.3. High Winds PRA Quality Statement for Permanent 15-Year ILRT Extension

The BSEP Units 1 and 2 High Winds PRA Peer Review was performed January 2012 using the ASME PRA Standard [Reference 41] and Regulatory Guide 1.200, Rev. 2 [Reference 43]. The purpose of this review was to establish the acceptability of the High Winds PRA for the spectrum of potential risk-informed plant licensing applications for which the High Winds PRA may be used. The 2012 BSEP High Winds PRA Peer Review was a full-scope review of all of the technical elements of the BSEP at-power 2011 MOR High Winds PRA against all technical elements of the High Winds PRA [Reference 36].

The ASME PRA Standard has 29 individual SRs pertaining to High Winds; the BSEP Peer Review included all of the SRs.

Table A.3-3 – BSEP High Winds PRA Assessment

Capability Categories	# SRs	% Total SRs
Not Met	9	31%
I	0	0%
I/II	1	3%
II	0	0%
II/III	5	17%
III	1	3%
Met (All)	13	45%
Total	29	100%

An F&O Finding closure technical review of the High Winds PRA and a focused-scope closure review of the High Winds HRA were conducted in July 2017 (documentation finalized in August 2017) to review all open High Winds PRA F&Os. Following the F&O closure all High Winds PRA F&Os are closed [Reference 36].