Exelon Generation.

4300 Winfield Road
Warrenville, IL 60555

www.exeloncorp.com

10 CFR 50.90

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October 26, 2016

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
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LaSalle County Station, Units 1 and 2
Renewed Facility Operating License Nos. NPF-11 and NPF-18
NRC Docket Nos. 50.373 and No. 374

Subject: License Amendment Request to Revise Technical Specifications 5.5.13, "Primary Containment Leakage Rate Testing Program," for Permanent Extension of Type A and Type C Leak Rate Test Frequencies

In accordance with 10 CFR 50.90, "Application for amendment of license, construction permit or early site permit," Exelon Generation Corporation, LLC (EGC) requests an amendment to Renewed Facility Operating License Nos. NPF-11 and NPF-18 for LaSalle County Station (LSCS), Units 1 and 2. The proposed change revises TS 5.5.13, "Primary Containment Leakage Rate Testing Program," to allow for the permanent extension of the Type A Integrated Leak Rate Testing (ILRT) and Type C Leak Rate Testing frequencies.

Specifically, the proposed change will revise LSCS TS 5.5.13, by replacing the references to Regulatory Guide (RG) 1.163, "Performance-Based Containment Leak-Test Program," with a reference to NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J," Revision 3-A, and the conditions and limitations specified in NEI 94-01, Revision 2-A, as the documents used by LSCS 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 TS 5.5.13 to delete the information regarding the performance of the next LSCS Type A tests to be performed no later than June 13, 2009, for Unit 1 and no later than prior to startup following the L2R12 refueling outage for Unit 2 as these Type A tests have already occurred.

Additionally, this LAR proposes an administrative change to the LSCS Unit 1 Renewed Facility Operating License to delete Condition 2.D.(e) of the LSCS Unit 1 Operating License regarding conducting the third Type A Test of each ten year service period when the plant is shutdown for the 10 year plant inservice inspection. Similarly, this LAR proposes an administrative change to the LSCS Unit 2 Renewed Facility Operating License to delete Condition 2.D.(c) of the LSCS Unit 2 Operating License regarding conducting the third Type A test of each ten year service period when the plant is shutdown for the 10 year plant inservice inspection.

The proposed amendment is risk-informed and follows the guidance in RG 1.174, "An Approach For Using Probabilistic Risk Assessment In Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," Revision 2. EGC has performed a LSCS-specific evaluation to assess the risk impact of the proposed amendment. A copy of the risk impact assessment is provided in Attachment 3.

The request is subdivided as follows:

- Attachment 1 provides a description and evaluation of the proposed changes.

- Attachment 2 provides the markup of the affected Renewed Facility Operating License and affected TS pages.

- Attachment 3 provides LS-LAR-06, "Risk Assessment for LSCS Regarding the ILRT (Type A) and DWBT Permanent Extension Request," Revision 1.

The proposed change has been reviewed by the LSCS Plant Operations Review Committee in accordance with the requirements of the EGC Quality Assurance Program.

EGC requests approval of the proposed amendment by October 26, 2017 in order to support the extension of the LSCS Unit 1 ILRT, which is required to be performed during the outage in the spring of 2018. Once approved, this amendment will be implemented within 60 days. This implementation period will provide adequate time for the affected station documents to be revised using the appropriate change control mechanisms.

In accordance with 10 CFR 50.91, "Notice for public comment; State consultation," paragraph (b), EGC is notifying the State of Illinois of this application for license amendment by transmitting a copy of this letter and its attachments to the designated State Official.

There are no regulatory commitments contained in this letter. Should you have any questions concerning this letter, please contact Ms. Lisa A. Simpson at (630) 657-2815.

I declare under penalty of perjury that the foregoing is true and correct. Executed on the 26th day of October 2016.

Respectfully,

David M. Gullott
Manager – Licensing
Exelon Generation Company, LLC

Attachments:
1) Evaluation of Proposed Change
2) Markup of Renewed Facility Operating Licenses and Technical Specifications Pages
3) Risk Impact Assessment of Extending the LSCS ILRT/DWBT Interval

cc: NRC Regional Administrator, Region III
NRC Senior Resident Inspector, LaSalle County Station
Illinois Emergency Management Agency – Division of Nuclear Safety

ATTACHMENT 1
Evaluation of Proposed Change

SUBJECT: License Amendment Request - Revise Technical Specifications 5.5.13 for Permanent Extension of Type A and Type C Leak Rate Test Frequencies

1.0 SUMMARY DESCRIPTION

In accordance with 10 CFR 50.90, "Application for amendment of license, construction permit or early site permit," Exelon Generation Corporation, LLC (EGC) requests an amendment to Renewed Facility Operating License Nos. NPF-11 and NPF-18 for LaSalle County Station (LSCS), Unit 1 and Unit 2. The proposed change revises Technical Specifications (TS) 5.5.13, "Primary Containment Leakage Rate Testing Program" to allow the following:

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

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

- Adopt the use of ANSI/ANS 56.8-2002, "Containment System Leakage Testing Requirements" (Reference 3).

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

Specifically, the proposed change contained herein revises LSCS TS 5.5.13 by replacing the references to Regulatory Guide (RG) 1.163, "Performance-Based Containment Leak-Test Program," (Reference 4) with a reference to NEI 94-01, Revision 3-A (Reference 1), and the conditions and limitations specified in NEI 94-01, Revision 2-A (Reference 2), as the documents used by LSCS 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 TS 5.5.13 to delete the information regarding the performance of the next LSCS Type A tests to be performed no later than June 13, 2009, for Unit 1 and no later than prior to startup following the L2R12 refueling outage for Unit 2 as these Type A tests have already occurred.

Additionally, this LAR proposes an administrative change to the LSCS Unit 1 Renewed Facility Operating License to delete Condition 2.D.(e) of the LSCS Unit 1 Operating License regarding conducting the third Type A Test of each ten year service period when the plant is shutdown for the 10 year plant inservice inspection. Similarly, this LAR proposes an administrative change to the LSCS Unit 2 Renewed Facility Operating License to delete Condition 2.D.(c) of the LSCS Unit 2 Operating License regarding conducting the third Type A test of each ten year service period when the plant is shutdown for the 10 year plant inservice inspection.

2.0 DETAILED DESCRIPTION

LSCS TS 5.5.13, "Primary Containment Leakage Rate Testing Program," currently states, in part:

> This program shall establish 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 RG 1.163, "Performance-Based Containment Leak-Testing Program," dated September 1995, as modified by the following exceptions:
>
> 1. NEI 94-01 – 1995, Section 9.2.3: The first Unit 1 Type A test performed after June 14, 1994 Type A test shall be performed no later than June 13, 2009.
>
> 2. NEI 94-01 – 1995, Section 9.2.3: The first Unit 2 Type A test performed after December 8, 1993 Type A test shall be performed prior to startup following L2R12.
>
> 3. The potential valve atmospheric leakage paths that are not exposed to reverse direction test pressure shall be tested during the regularly scheduled Type A test. The program shall contain the list of the potential valve atmospheric leakage paths, leakage rate measurement method, and acceptance criteria. This exception shall be applicable only to valves that are not isolable from the primary containment free air space.

The proposed change will revise TS 5.5.13 to state, in part:

> This program implements 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 exception:
>
> 1. The potential valve atmospheric leakage paths that are not exposed to reverse direction test pressure shall be tested during the regularly scheduled Type A test. The program shall contain the list of the potential valve atmospheric leakage paths, leakage rate measurement method, and acceptance criteria. This exception shall be applicable only to valves that are not isolable from the primary containment free air space.

The proposed changes to LSCS TS 5.5.13 will replace the reference to RG 1.163 with a reference to NEI Topical Report NEI 94-01, Revisions 2-A and 3-A. This LAR also proposes administrative changes to two exceptions currently listed in TS 5.5.13. The TS 5.5.13 exception regarding the performance of the LSCS Unit 1 Type A test to be performed no later than June 13, 2009, will be deleted as that Type A test has already occurred. Additionally, the TS 5.5.13 exception regarding the performance of the next LSCS Unit 2 Type A test to be performed no later than prior to startup following the L2R12 refueling outage will be deleted as that test has already occurred.

LSCS Unit 1 Renewed Facility Operating License, Condition 2.D.(e) currently states:

> An exemption from the requirement of paragraph III.D of Appendix J to conduct the third Type A test of each ten-year service period when the plant is shutdown for the 10-year plan inservice inspections. Exemption (e) is described in the safety evaluation accompanying amendment No. 102 to this License.

LSCS Unit 2 Renewed Facility Operating License, Condition 2.D.(c) currently states:

> An exemption from the requirement of paragraph III.D of Appendix J to conduct the third Type A test of each ten-year service period when the plant is shutdown for the 10-year plan inservice inspections.

Condition 2.D.(e) of the LSCS Unit 1 Operating License regarding conducting the third Type A Test of each ten year service period when the plant is shutdown for the 10 year plant inservice inspections will be deleted since the Type A test frequency will be 15 years following approval of this LAR. Additionally, Condition 2.D.(c) of the LSCS Unit 2 Operating License regarding conducting the third Type A test of each ten year service period when the plant is shutdown for the 10 year plant inservice inspections will be deleted since the Type A test frequency will be 15 years following approval of this LAR.

Markups of the proposed changes to TS 5.5.13 and of the Renewed Facility Operating Licenses are provided in Attachment 2.

Attachment 3 contains the plant specific risk assessment conducted to support this proposed change. This risk assessment followed the guidelines of Nuclear Regulatory Commission (NRC) RG 1.174, Revision 2 (Reference 5) and NRC RG 1.200, Revision 2 (Reference 6). The risk assessment concluded that the increase in risk as a result of this proposed change is small and is well within established guidelines.

3.0 TECHNICAL EVALUATION

3.1 Description of Primary Containment System

The primary containment is a concrete structure with the exception of the drywell head and access penetrations, which are fabricated from steel. The concrete is designed to resist all loads associated with the design-basis accident. The primary containment walls have a steel liner, which acts as a low leakage barrier for release of fission products.

The walls of the primary containment are posttensioned concrete; the base mat is conventional reinforced concrete. The dividing floor between the drywell and suppression chamber is conventional reinforced concrete and is supported on a cylindrical base at its center, on a series of concrete columns and from the containment wall at the periphery of the slab.

The drywall floor is rigidly connected to the primary containment wall. The primary containment walls support the reactor building floor loads and, in addition, also serve as the biological shield. A full moment shear connection is provided by dowels and shear lugs welded to the

reinforced liner plate. The thermal expansion is accounted for in the containment design; the resulting forces and moments are accommodated within the allowable stress limits.

The walls of the primary containment structure are posttensioned, using the BBRV system of posttensioning utilizing parallel lay, unbounded type tendons. The tendons are fabricated from ninety (90) one-quarter inch diameter, cold drawn, stress relieved, pre-stressing grade wire. Each tendon is encased in a conduit. The walls are pre-stressed both vertically and horizontally for floor elevations below 820 ft. The horizontal tendons are placed in a 240 degree system using three buttresses as anchorages with the tendons staggered so that two-thirds of the tendons at each buttress terminate at that buttress. For floor elevations above 820 ft, the horizontal tendons are placed in a 360 degree pattern system using two buttresses as anchorages. Access to the tendon anchorages is maintained to allow for periodic inspection.

All liner joints have full penetration welds. The field welds have leak tightness testing capability by having a small steel channel section welded over each liner weld. Fittings are provided in the channel for leak testing of the liner welds under pressure. The actual containment leakage boundary during normal operation and accident conditions consists of the liner and liner joint butt welds when the leak test channel is vented to the containment atmosphere and the combined containment liner, liner joint butt welds, containment liner leak test channels, channel fillet welds and the leak test connections when the leak test channel test connection plugs are installed. The liner anchorage system considers the effects of temperature, negative pressure, pre-stressing, and stress transfer around penetrations.

3.1.1 Drywell

The drywell is a steel-lined posttensioned concrete vessel in the shape of a truncated cone having a base diameter of approximately 83 ft and a top diameter of 32 ft. The floor of the drywell serves both as a pressure barrier between the drywell and suppression chamber and as the support structure for the reactor pedestal and downcomers. The drywell head is bolted at a steel ring girder attached to the top of the concrete containment wall and is sealed with a double seal. The double seal on the head flange provides a plenum for determining the leak tightness of the bolted connection. The base of the ring serves as the top anchorage for the vertical pre-stressing tendons and the top of the ring serves as anchorage for the drywell head.

The drywell houses the reactor and its associated auxiliary systems. The primary function of the drywell is to contain the effects of a design-basis recirculation line break and direct the steam released from a pipe break into the suppression chamber pool. The drywell is designed to resist the forces of an internal design pressure of 45 psig in combination with thermal, seismic, and other forces.

The drywell is provided with a 12-foot diameter equipment hatch for removal of equipment for maintenance and an air lock for entry of personnel into the drywell. Under normal plant operations, the equipment hatch is kept sealed and is opened only when the plant is shut down for refueling and/or maintenance.

The equipment hatch is covered with a steel dished head bolted to the hatch opening frame that is welded to the steel liner. A double seal is utilized to ensure leak tightness when the hatch is subjected to either an internal or external pressure. The space between the double seal serves as a plenum for leak testing the hatch seal.

The personnel air lock is a cylindrical intake welded to the steel liner. The double doors are interlocked to maintain containment integrity during operation.

All the welds that make up the vapor barrier have test channels to permit leak testing of the welds: When the leak test channel test connections are plugged, the leak test channel is part of the vapor barrier.

3.1.2 Pressure Suppression Chamber and Vent System

The primary function of the suppression chamber is to provide a reservoir of water capable of condensing the steam flow from the drywell and collecting the non-condensable gases in the suppression chamber air space. The suppression chamber is a stainless steel-lined posttensioned concrete vessel in the shape of a cylinder, having an inside diameter of 86 ft, 8 in. The foundation mat serves as the base of the suppression chamber. The suppression chamber is designed for the same internal pressure as the drywell in combination with the thermal, seismic, and other forces. The liner design and testing are the same as the primary containment and drywell systems.

The entire suppression chamber is lined with stainless steel. The drywell floor support columns are also provided with a stainless steel liner on the outside surface.

Two 36-inch diameter openings are provided for access into the suppression chamber for inspection. Under normal plant operation, these access openings are kept sealed. They are opened only when the plant is shut down for refueling and/or maintenance. The access openings are located in the cylindrical walls of the chamber 14 ft, 2 in above the suppression pool water level. The hatch cover is designed with a double seal and test plenum to ensure leak tightness.

The suppression chamber vent system consists of 98 downcomer pipes open to the drywell and submerged 12 ft, 4 in below the low water level of the suppression pool, providing a flow path for uncondensed steam into the water. Each downcomer has a 23-1/2 in internal diameter. The downcomers project 6 in above the drywell floor to prevent flooding from a broken line. Each vent pipe opening is shielded by a 1-in thick steel deflector plate to prevent overloading any single vent pipe by direct flow from a pipe break to that particular vent.

3.1.3 Vacuum Relief System

Vacuum relief valves are provided between the drywell and suppression chamber to prevent exceeding the drywell floor negative design pressure and back flooding of the suppression pool water into the drywell.

In the absence of vacuum relief valves, drywell flooding could occur following isolation of a blow down in the drywell. Condensation of blow down steam on the drywell walls and structures could result in a negative pressure differential between the drywell and suppression chamber.

The vacuum relief valves (four assemblies) are outside the primary containment and form an extension of the primary containment boundary. The vacuum relief valves are mounted in special piping which connects the drywell and suppression chamber, and are evenly distributed

around the suppression chamber air volume to prevent any possibility of localized pressure gradients from occurring due to geometry. In each vacuum breaker assembly, two local manual butterfly valves, one on each side of the vacuum breaker, are provided as system isolation valves should failure of the vacuum breaker occur. The vacuum relief valves are instrumented with redundant position indication and are indicated in the main control room. The valves are provided with the capability for local manual testing. This design provides adequate assurance of limiting the differential pressure between the drywell and suppression chamber and assures proper valve operation and testing during normal plant operation. No vacuum relief valves are provided between the drywell and the reactor building atmosphere. The concrete containment structure has the ability to accommodate sub atmospheric pressures of approximately 5 psi absolute.

3.1.4 Secondary Containment

The Secondary Containment consists of the Reactor Building, the equipment access structure, and a portion of the main steam tunnel and has a minimum free volume of 2,875,000 cubic ft.

The reactor building completely encloses the reactor and its primary containment. The structure provides secondary containment when the primary containment is closed and in service, and primary containment when the primary containment is open as it is during the refueling period. The reactor building houses the refueling and reactor servicing equipment, the new and spent fuel storage facilities, and other reactor auxiliary or service equipment, including the reactor core isolation cooling system, reactor water clean up demineralizer system, stand by liquid control system, control rod drive system equipment, the emergency core cooling system and electrical equipment components.

The reactor building exterior walls and superstructure up to the refueling floor are constructed of reinforced concrete. Above the level of the refueling floor, the building structure is fabricated of structural steel members, insulated siding and a metal roof. Joints in the superstructure paneling are detailed to assure leak tightness. Penetrations of the reactor building are designed with leakage characteristics consistent with leakage requirements of the entire building. The reactor building is designed to limit the in leakage of 100% of the reactor building free volume per day at a negative pressure of 0.25 inch water gauge, while operating the standby gas treatment system. The building structure above the refueling floor is also designed to contain a negative pressure of 0.25 inch water gauge.

Personnel entrance to the reactor building is through an interlocking double door airlock. Rail car access openings in the reactor building at elevation 710 ft 6 in provided with double doors to assure that building access will not interfere with maintaining the integrity of secondary containment.

3.1.5 Containment Wall

The containment wall varies from a 4-ft minimum thickness from the base slab elevation of 673 ft, 4 in to elevation 732 ft, 8 in; and a 6-ft thickness from elevation 732 ft, 8 in to elevation 815 ft, 2-1/2 in. Containment reinforcing consists of hoop and meridional reinforcing that is typically placed in each face of the containment wall. Prestressing tendons are arranged in the hoop and meridional directions.

Reinforcing Layout

Reinforcing consists primarily of #11 bars in both meridional and hoop directions and #7 bars for shear reinforcing.

Prestressing System and Layout

The wall of the primary containment is prestressed using the posttensioning BBRV system. This system utilizes parallel lay and unbonded type tendons, each composed of button-headed wires and end anchorage hardware.

There are 188 horizontal tendons placed in a 240 degree system to the elevation of 792 ft and in a 360 degree system above the elevation of 792 ft. For the 240 degree system, three buttresses are equally spaced around the containment, and each horizontal tendon is anchored at buttresses 240 degrees apart, bypassing the intermediate buttress. For the 360 degree system, two buttresses are on opposite sides of the containment, and each tendon starts and ends at the same buttress.

There are 120 meridional tendons used in the containment wall. These are anchored at the underside of the base slab as shown in Figure 3.8-13. One-half of the tendons terminate at midheight of the containment wall at the elevation of 786 ft, 6 in. One-quarter of the tendons anchor the drywell head support ring to the concrete at the elevation of 815 ft, 2-1/2 in. The remaining one-quarter of the tendons extend to elevation 841 ft 6 in and elevation 821 ft, 6 in where they are anchored in recesses.

The tendons are placed inside conduits embedded in the concrete and are protected by corrosion preventive grease. All anchorages for the prestressing system are located outside the primary containment structure and are so designed, furnished and fabricated that the prestressing tendons can be installed after concrete work is complete.

The posttensioning of the tendons takes place after the entire containment and reactor building are constructed up to the operating floor level. The posttensioning sequence is described below.

The vertical tendons are tensioned first. The longer tendons running the full height of the containment are tensioned prior to the shorter ones. The force is applied from the tendon access tunnel using three equally spaced jacks, simultaneously stressing three tendons. The three jacks are then moved over three tendons and the tensioning pattern is continued until all tendons are tensioned.

The hoop tendons are tensioned next. Each horizontal tendon is tensioned from both ends simultaneously. The tensioning procedures use six jacks to tension an entire ring consisting of three tendons. Every third ring along the entire height of the containment is tensioned before returning to stress the intermediate tendons. The LSCS containments are carefully checked for the partial pre-stressing stages. The effects of elastic shortening are accounted for in one of the following two ways:

a. by tensioning the first stressed tendons to a higher value than the last ones by the anticipated amount of elastic shortening; or

b. by reducing the tendon capacity considered in design, accounting for the effects of creep, shrinkage, and relaxation.

Friction tests are made on typical tendons of the containment structure prior to the stressing of hoop tendons. The friction factors thus established are used to calculate the tendon elongations. The measured tendon elongations that exceed +/- 10% of the calculated values are investigated and corrected where necessary.

3.1.6 Containment Isolation System

The primary objective of the containment isolation system is to provide protection against the release of the radioactive materials to the environment through the fluid system lines penetrating the containment. This objective is accomplished by ensuring that isolation barriers are provided in all fluid lines that penetrate the primary containment, and that automatic closure of the appropriate isolation valves occurs. Redundancy is provided in design aspects to satisfy the requirement that an active failure of a single valve or component does not prevent containment isolation. Electrical redundancy is provided in isolation valve arrangements to eliminate dependence on a single power source to attain isolation. Electrical cables for isolation valves in the same process line have been routed separately. Cables have been selected based upon the specific environment to which they will be subjected.

The governing conditions under which containment isolation becomes mandatory are high drywell pressure or low water level in the reactor vessel. One or both of these signals initiate closure of isolation valves not required for emergency shutdown of the plant. These same signals also initiate the Emergency Core Cooling System (ECCS). The valves associated with an ECCS may be closed remote manually from the control room or close automatically, as appropriate.

3.1.7 Penetrations

Access to the interior of the containment structure is provided by a personnel lock, a control rod drive removal hatch, an equipment hatch located just above the drywell floor level, and two access hatches in the suppression pool at an elevation of 714 ft. The equipment and access hatches are not utilized during normal operation or at other times when containment is required. The containment structure is also penetrated by process pipe lines and electrical penetration assemblies.

Pipe Penetrations

The pipe penetration sleeve is embedded into the concrete as it penetrates the containment. Air gaps are provided around all pipes. Insulation and cooling coils are provided around hot pipes to reduce thermal stress in the containment during normal operations. In addition to their function as a primary containment barrier, the penetrations serve as anchors to the pipes and are designed to carry the loads associated with a postulated pipe rupture. Thermal growth and movement is taken up in the piping system.

Electrical Penetrations

Canister-type electrical penetration assemblies are used to extend electrical conductors through the pressure boundary of the containment structure. Electrical penetrations are functionally grouped into low voltage power, low voltage control cable penetration assemblies, medium voltage power cable penetration assemblies, and shielded cable penetration assemblies. The penetrations are hermetically sealed and provide a means for periodic leak testing. An assembly is sized to be inserted in the 12-inch schedule 80 penetration nozzles, which are furnished as part of the containment structure.

Drywell Head

The drywell head ring plate assembly is anchored to the concrete containment wall by one-quarter (30) of the vertical tendons.

3.1.8 Combustible Gas Control in Containment

In order to assure that containment integrity is not endangered due to the generation of combustible gases following a postulated LOCA, systems for controlling the relative concentrations of such gases are provided within the plant. The system includes subsystems for mixing the containment atmosphere, monitoring hydrogen concentration, reducing combustible gas concentrations, and as a backup, purging.

The combustible gas control system has the capability for monitoring the hydrogen concentration in drywell and suppression chamber and alarming as the hydrogen concentration reaches 4 percent. It also has the capability of mixing the atmospheres of both drywell and suppression chamber. It also will control the combustible gas concentrations in primary containment without reliance on purging and without the release of radioactive material to the environment.

The combustible gas control system will be activated after a LOCA in time to assure that the hydrogen concentration does not exceed four volume percent of hydrogen in either the drywell or wet well atmospheres. In addition, the LSCS containment is nitrogen inerted to an oxygen concentration of 4 percent by volume. This is below the combustible limit of oxygen in hydrogen but still provides enough oxygen to react with all the hydrogen that would be produced by the metal water reaction.

3.2 Justification for the Technical Specification Change

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

The testing requirements of 10 CFR Part 50, Appendix J, provide assurance that leakage from the containment, including systems and components that penetrate the containment, does not exceed the allowable leakage values specified in the TS. Title 10 CFR Part 50, Appendix J also ensures that periodic surveillance of reactor containment penetrations and isolation valves is performed so that proper maintenance and repairs are made during the service life of the containment and the systems and components penetrating primary containment. The limitation on containment leakage provides assurance that the containment would perform its design function following an accident up to and including the plant design basis accident. Appendix J identifies three types of required tests: 1) Type A tests, intended to measure the primary

containment overall integrated leakage rate; 2) Type B tests, intended to detect local leaks and to measure leakage across pressure-containing or leakage limiting boundaries (other than valves) for primary containment penetrations; and 3) Type C tests, intended to measure containment isolation valve leakage rates. Type B and C tests identify the vast majority of potential containment leakage paths. Type A tests identify the overall (integrated) containment leakage rate and serve to ensure continued leakage integrity of the containment structure by evaluating those structural parts of the containment not covered by Type B and C testing.

In 1995, 10 CFR Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors," was amended to provide a performance-based Option B for the containment leakage testing requirements. Option B requires that test intervals for Type A, Type B, and Type C testing be determined by using a performance-based approach. Performance-based test intervals are based on consideration of the operating history of the component and resulting risk from its failure. The use of the term "performance-based" in 10 CFR Part 50, Appendix J refers to both the performance history necessary to extend test intervals as well as to the criteria necessary to meet the requirements of Option B.

Also in 1995, RG 1.163 (Reference 4) was issued. The RG endorsed NEI 94-01, Revision 0, (Reference 7) with certain modifications and additions. Option B, in concert with RG 1.163 and NEI 94-01, Revision 0, allows licensees with a satisfactory ILRT performance history (i.e., two consecutive, successful Type A tests) to reduce the test frequency for the containment Type A (ILRT) test from three tests in 10 years to one test in 10 years. This relaxation was based on an NRC risk assessment contained in NUREG-1493, (Reference 8) and Electric Power Research Institute (EPRI) TR-104285 (Reference 9) both of which showed that the risk increase associated with extending the ILRT surveillance interval was very small. In addition to the 10-year ILRT interval, provisions for extending the test interval an additional 15 months was considered in the establishment of the intervals allowed by RG 1.163 and NEI 94-01, but that this "should be used only in cases where refueling schedules have been changed to accommodate other factors."

In 2008, NEI 94-01, Revision 2-A (Reference 2), was issued. NEI 94-01, Revision 2-A, describes an acceptable approach for implementing the optional performance-based requirements of Option B to 10 CFR Part 50, Appendix J, subject to the limitations and conditions noted in Section 4.0 of the NRC Safety Evaluation (SE) 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 (September 1995). It delineates a performance-based approach for determining Type A, Type B, and Type C containment leakage rate surveillance testing frequencies. Justification for extending test intervals is based on the performance history and risk insights.

In 2012, NEI 94-01, Revision 3-A (Reference 1), was issued. NEI 94-01, Revision 3-A, describes an acceptable approach for implementing the optional performance-based requirements of Option B to 10 CFR Part 50, Appendix J and includes provisions for extending Type A ILRT intervals to up to 15 years. NEI 94-01 has been endorsed by RG 1.163 and NRC SEs dated June 25, 2008 (Reference 10) and June 8, 2012 (Reference 11) as an acceptable methodology for complying with the provisions of Option B to 10 CFR Part 50. The regulatory positions stated in RG 1.163 as modified by NRC SEs of June 25, 2008 and June 8, 2012 are incorporated in NEI 94-01, Revision 3-A. It delineates a performance-based approach for determining Type A, Type B, and Type C containment leakage rate surveillance testing frequencies. Justification of extending test intervals is based on the performance

history and risk insights. Extensions of Type B and Type C test intervals are allowed based upon completion of two consecutive periodic as-found tests where the results of each test are within a licensee's allowable administrative limits. Intervals may be increased from 30 months up to a maximum of 120 months for Type B tests (except for containment airlocks) and up to a maximum of 75 months for Type C tests. If a licensee considers extended test intervals of greater than 60 months for Type B or Type C tested components, the review should include the additional considerations of as-found tests, schedule and review as described in NEI 94-01, Revision 3-A, Section 11.3.2.

NEI 94-01, Revision 2-A, NRC SE Section 3.1.1.2 describes the following regarding the use of grace in the deferral of ILRTs past the 15 year interval:

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

NEI 94-01, Revision 3-A, Section 10.1 concerning the use of grace in the deferral of Type B and Type C LLRTs past intervals of up to 120 months for the recommended surveillance frequency for Type B testing and up to 75 months for Type C testing, states:

> Consistent with standard scheduling practices for Technical Specifications Required Surveillances, intervals of up to 120 months for the recommended surveillance frequency for Type B testing and up to 75 months for Type C testing given in this section may be extended by up to 25% of the test interval, not to exceed nine months.
>
> Notes: For routine scheduling of tests at intervals over 60 months, refer to the additional requirements of Section 11.3.2.
>
> Extensions of up to nine months (total maximum interval of 84 months for Type C tests) are permissible only for non-routine emergent conditions. This provision (nine month extension) does not apply to valves that are restricted and/or limited to 30 month intervals in Section 10.2 (such as BWR MSIVs) or to valves held to the base interval (30 months) due to unsatisfactory LLRT performance.

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

> The basis for acceptability of extending the ILRT interval out to once per 15 years was the enhanced and robust primary containment inspection program and the local leakage rate testing of penetrations. Most of the primary containment leakage

experienced has been attributed to penetration leakage and penetrations are thought to be the most likely location of most containment leakage at any time.

3.2.2 Current LSCS Primary Containment Leakage Rate Testing Program Requirements

10 CFR Part 50, Appendix J was revised, effective October 26, 1995, to allow licenses to choose containment leakage testing under either Option A, "Prescriptive Requirements," or Option B, "Performance-Based Requirements." On March 11, 1996 the NRC approved License Amendments Nos. 110 and 95 for LSCS Units 1 and 2, respectively (Reference 12) authorizing the implementation of 10 CFR Part 50, Appendix J, Option B for Type A, B and C tests.

Current TS 5.5.13 requires that a program be established to comply with the containment leakage rate testing requirements of 10 CFR 50.54(o) and 10 CFR Part 50, Appendix J, Option B, as modified by approved exemptions. The program is required to be in accordance with the guidelines contained in RG 1.163. RG 1.163 endorses, with certain exceptions, NEI 94-01, Revision 0, as an acceptable method for complying with the provisions of Appendix J, Option B.

RG 1.163, Section C.1 states that licensees intending to comply with 10 CFR Part 50, Appendix J, Option B, should establish test intervals based upon the criteria in Section 11.0 of NEI 94-01 (Reference 7) rather than using test intervals specified in American National Standards Institute (ANSI)/American Nuclear Society (ANS) 56.8-1994. NEI 94-01, Section 11.0 refers to Section 9, which states that Type A testing shall be performed during a period of reactor shutdown at a frequency of at least once per ten years based on acceptable performance history. Acceptable performance history is defined as completion of two consecutive periodic Type A tests where the calculated performance leakage was less than 1.0 L_a (where L_a is the maximum allowable leakage rate at design pressure). Elapsed time between the first and last tests in a series of consecutive satisfactory tests used to determine performance shall be at least 24 months.

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

3.2.3 LSCS 10 CFR Part 50, Appendix J, Option B Licensing History

March 11, 1996

The NRC issued Amendment Nos. 110 (LSCS Unit 1) and 95 (LSCS Unit 2) which revised TS 5.5.13 to incorporate 10 CFR Part 50, Appendix J, Primary Reactor Containment Leakage Testing for Water Cooled Power Reactors," Option B. (Reference 12)

November 7, 2001

The NRC issued Amendment Nos. 149 (LSCS Unit 1) and 135 (LSCS Unit 2) which revised TS requirements concerning drywell-to-suppression chamber bypass leakages. Specifically, the Amendments extended the baseline interval specified in Surveillance Requirement (SR) 3.6.1.1.3 for the drywell-to-suppression chamber bypass leakage test from 24 months to 120 months and added SR 3.6.1.1.4 and SR 3.6.1.1.5 which established specific testing requirements for the suppression chamber-to-drywell vacuum breakers. (Reference 13)

November 19, 2003

The NRC issued Amendment Nos. 162 (LSCS Unit 1) and 148 (LSCS Unit 2) which revised TS 5.5.13, "Primary Containment Leakage Rate Testing Program." This amendment allowed a one-time deferral of the primary containment Type A test to no later than June 13, 2009, for Unit 1 and no later than December 7, 2008, for Unit 2. (Reference 14)

October 14, 2004

The NRC issued Amendment Nos. 168 (LSCS Unit 1) and 154 (LSCS Unit 2) to revise TS 5.5.13 to allow an exception to the testing guidance contained in RG 1.163, "Performance-Based Containment Leak-Test Program." Specifically, the TS change will allow potential valve atmospheric leakage paths (e.g., valve stem packing) that are not exposed to test pressure during reverse-direction Type B or C tests (local leakage rate tests) to instead be tested during regularly scheduled Type A tests (integrated leakage rate tests). (Reference 15)

January 24, 2007

The NRC issued Amendment No. 166, which revised TS 5.5.13 to reflect a one-time extension of the LSCS Unit 2 primary containment Type A integrated leak rate test from the current requirement of "no later than December 7, 2008," to "prior to startup following the LSCS Unit 2 refueling outage L2R12." This Amendment extended the previously approved one-time extension of the containment ILRT from a 10-year test interval to a 15-year interval for LSCS Unit 2 by an additional 3 months to coincide with the L2R12 refueling outage. (Reference 16)

September 6, 2010

The NRC issued Amendment Nos. 197 (LSCS Unit 1) and 184 (LSCS Unit 2), which revised TS 5.5.13 to support the application of alternative source term methodology with respect to the loss-of-coolant accident and the fuel handling accident. The changed revised TS 5.5.13.a to increase the maximum allowable primary containment leakage rate, L_a at P_a, from 0.635 percent to 1.0 percent of primary containment air weight per day. (Reference 17)

January 29, 2015

The NRC issued Amendment Nos. 212 (LSCS Unit 1) and 198 (LSCS Unit 2), which revised TS 5.5.13 to increase the peak calculated primary containment internal pressure. The amendments were requested to resolve a non-conservative TS. The peak calculated primary containment internal pressure (Pa) value was changed from 39.9 psig to 42.6 psig. (Reference 18)

3.2.4 Continued Acceptability of TS Amendments 168 (Unit 1) and 154 (Unit 2)

By application dated October 14, 2004 (Reference 14), EGC requested changes to the TS for LSCS, Units 1 and 2.

The amendments revised TS 5.5.13, "Containment Leakage Rate Testing Program," to allow an exception to the testing guidance contained in RG 1.163, "Performance-Based Containment Leak-Test Program." Specifically, the TS change allowed potential valve atmospheric leakage paths (e.g., valve stem packing) that are not exposed to test pressure during reverse-direction Type B or C tests (local leakage rate tests) to instead be tested during regularly scheduled Type A tests (integrated leakage rate tests).

Amendments 168 and 154 revised TS 5.5.13 by adding the following exception:

3. The potential valve atmospheric leakage paths that are not exposed to reverse direction test pressure shall be tested during the regularly scheduled Type A test. The program shall contain the list of the potential valve atmospheric leakage paths, leakage rate measurement method, and acceptance criteria. This exception shall be applicable only to valves that are not isolable from the primary containment free air space.

NEI 94-01, Rev. 2-A, Section 1.1 states (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 (SE) 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 SE 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:

LSCS will continue to use the provisions of TS 5.5.13.a.

3.2.5 Integrated Leakage Rate Testing History (ILRT)

As noted previously, LSCS TS 5.5.13 currently requires Type A, B, and C testing in accordance with RG 1.163, which endorses the methodology for complying with Option B. Since the adoption of Option B, the performance leakage rates are calculated in accordance with NEI 94-01, Section 9.1.1 for Type A testing. Tables 3.2.5-1 and 3.2.5-2 list the past LSCS Type A ILRT results.

Table 3.2.5-1 – LSCS Unit 1 Type A Test History

Test Date	Total Leakage (Note 1)	Acceptance Limit (Note 1)
5/14/82	0.3933	0.634
6/4/86	0.4243	0.634
12/23/89	0.3200	0.634
1/14/93	0.4243	0.634
6/14/94	0.2355	0.634
2008 (L1R12)	0.4720	0.634

Table 3.2.5-2 – LSCS Unit 2 Type A Test History

Test Date	Total Leakage (Note 1)	Acceptance Limit (Note 1)
6/24/83	0.2309	0.634
6/1/87	0.5395	0.634
6/3/90	0.5042	0.634
3/28/92	0.3760	0.634
12/8/93	0.3794	0.634
2009 (L2R12)	0.4270	0.634

Note 1: Leakage rates are expressed in units of containment air weight percent per day at test pressure equal to the calculated peak containment internal pressure related to the DBA - P_a. Calculated results are expressed at a 95% confidence level plus leakage attributed to non-vented penetrations. The maximum allowable primary containment leakage rate allowed by Option B during containment leak rate testing is 0.634% containment air weight percent per day (1.0 L_a).

The Type A test acceptance criteria is as follows in accordance with TS 5.5.13:

- The peak calculated primary containment internal pressure for the design basis loss of coolant accident, P_a, is 42.6 psig.

- The maximum allowable primary containment leakage rate, L_a, at P_a, is 1.0% of primary containment air weight per day.
- The leakage rate acceptance criteria are:
  - Primary containment overall leakage rate acceptance criterion is ≤ 1.0 L_a. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are ≤ 0.60 L_a for the combined Type B and Type C tests, and ≤ 0.75 L_a for Type A tests.

3.2.6 Bypass Leak Rate Test Risk Assessment

The drywell-to-suppression chamber bypass leakage test (DWBT) measures the total leakage between the drywell airspace and the suppression chamber airspace including the leakage through the four suppression chamber-drywell vacuum breakers. SR 3.6.1.1.3 verifies that the total drywell-to-suppression chamber bypass leakage area is less than or equal to the acceptable $A/(k)^{1/2}$ design value of 0.030 square ft, at an initial differential pressure of greater than or equal to 1.5 pounds per square inch differential (psid).

In an amendment dated November 7, 2001, the NRC approved TS revisions to the scheduling of the drywell to suppression chamber bypass test and the suppression chamber to drywell vacuum breaker leakage testing. The amendments required the drywell to suppression chamber bypass test to be conducted on a 10-year frequency and the drywell to suppression chamber vacuum breaker leakage tests to be conducted on a 24-month frequency. The latest drywell to suppression chamber bypass tests for LSCS Unit 1 was conducted on February 25-26, 2008 and LSCS Unit 2 was conducted on February 7-8, 2009. These tests were performed following the Integrated Leak Rate Tests. The current surveillance interval is controlled under the LSCS Surveillance Frequency Control Program (SFCP) and will be revised under the SFCP to once every 15 years following approval of this LAR.

A review of the past test history for the drywell-to-suppression chamber bypass leakage test has identified no failures. The following are the test results:

Table 3.2.6-3 – DWBT Test Results Compared to Tech Spec Allowable (SCFM)

Unit 1 (SCFM)	% of TS Allowable	Unit 2 (SCFM)	% of TS Allowable
2008 - 9.80	13.2%	2009 - 5.34	7.1%
2000 - 1.51	2.0%	1999 - 1.04	1.4%
1999 - 0.78	1.0%	1998 - 0.82	1.1%
1995 - 2.20	3.0%	1996 - 0.01	0.01%

The history of test results indicates that the typical leakage is about one to two orders of magnitude below the acceptance criteria (which are set at an order of magnitude below the design basis limit). This excellent history combined with the conservatism included in the allowable leakage rate helps to support the qualitative justification provided below and helps support the low likelihood of a large undetected bypass leakage in the risk assessment.

Qualitative Justification for DWBT Interval Extension

Several potential bypass leakage pathways exist:

- Leakage through the diaphragm floor penetrations (e.g., SRV discharge line downcomers)
- Cracks in the diaphragm floor/liner plate
- Cracks in the downcomers in the suppression pool airspace region
- Valve seat leakage in the four sets of drywell-to-suppression chamber containment vacuum breakers

The most likely source of potential bypass leakage is the four sets of drywell-to-suppression chamber vacuum breakers. The drywell-to-suppression chamber bypass leak test is currently performed on a schedule consistent with the ILRT. However, a vacuum breaker leakage test is performed every 24 months. Individual and total drywell-to-suppression chamber vacuum relief valve bypass leakage is verified to be acceptable in accordance with TS SR 3.6.1.1.4 and SR 3.6.1.1.5 and the SFCP.

A functional test of each vacuum breaker is performed every 92 days in accordance with TS SR 3.6.1.6.2 and the SFCP. Verification that each vacuum breaker is closed is performed every 14 days in accordance with TS SR 3.1.1.6.1 and the SFCP.

The vacuum breaker leakage test and stringent acceptance criteria, combined with the historical negligible non-vacuum breaker leakage, and thorough periodic visual inspection provide an equivalent level of assurance as the DWBT that that the drywell to suppression chamber bypass leakage can be detected and/or measured in a reasonable timeframe.

Risk Metrics Associated with DWBT Interval Extension:

In accordance with the Risk Impact Assessment of Extending the LSCS DWBT Interval contained in Attachment 3, Appendix B of this submittal, the changes in CDF and LERF meet the RG 1.174 (Reference 5) acceptance guidelines for very small risk change. The change in population dose rate is well below the acceptance criteria of ≤ 1.0 person-rem/yr or < 1.0% person-rem/yr defined in the EPRI guidance document (Reference 19). Change in CCFP of 0.01% is approximately two orders of magnitude below the EPRI 1009325 Revision 2-A (Reference 20) guidance document acceptance criteria of less than 1.5%.

The change in the risk metrics associated with the DWBT interval extension calculated above are based on internal events. The changes are small and would not significantly change even if the potential impact from external events as calculated in Section 5.7.5 of the main body of Attachment 3 of this Submittal were to be incorporated. In summary, the change in the DWBT interval extension to 1 in 15 years is found to result in an acceptable change in risk.

3.2.7 Net Positive Suction Head (NPSH) for ECCS Pumps

The ECCS pump specifications are such that the NPSH requirements for High Pressure Core Spray (HPCS), Low Pressure Core Spray (LPCS) and Low Pressure Core Injection (LPCI) are met with the containment atmosphere at atmospheric pressure and the suppression pool at saturation temperature. Calculations were performed to evaluate ECCS NPSH requirements

post design basis accident (DBA) LOCA. The calculations used the following conservative inputs:

1. Maximum ECCS pump flow – unthrottled system, reactor pressure at 0 psid, maximizing suction friction losses at NPSH required.

   LPCI Pump – 8100 gallons per minute (gpm)
   LPCS Pump – 8100 gpm
   HPCS Pump – 7000 gpm

2. Increased clean, commercial steel piping friction losses to account for potential aging effects, thus maximizing suction losses. An absolute roughness of 0.0005 ft was used (vs. 0.00015 ft for clean pipe), resulting in an increase in calculated head loss of about 22 percent.

3. To account for strainer plugging, the head loss across the debris bed formed on the stacked disk replacement strainers installed at the suction of the ECCS pumps due to accumulation of insulation debris and miscellaneous fibrous and particulate matter debris produced as a result of a LOCA is determined. This head loss is added to the head loss associated with a clean strainer.

4. Containment conditions used in the analysis are containment at atmospheric pressure and the suppression pool at saturation temperature (212°F).

5. A minimum suppression pool elevation of 695 ft, 11-1/2 in is used. This includes a worst-case post-LOCA drawdown of 43 in.

6. NPSH required values for the ECCS pumps are taken from the vendor pump curves. With respect to the pump suction inlet centerline, the required NPSH is as follows:

   LPCI Pump – 14.0 ft @ 8100 gpm
   LPCS Pump – 2.0 ft @ 8100 gpm
   HPCS Pump – 5.0 ft @ 7000 gpm

The calculations determined that adequate NPSH exists to meet ECCS pump requirements post LOCA for all ECCS pumps. Additionally, adequate margin exists to ensure that flashing does not occur in any of the ECCS pump suction lines post-LOCA.

The emergency core cooling system pumps, which include the containment heat removal system pumps, take suction from the suppression pool. Calculations for determining the available net positive suction head (NPSH) to these pumps are based on saturated water in the suppression pool, and will therefore be independent of containment pressure. The increase in containment pressure during a loss-of-coolant accident (LOCA) is not included in the determination of available NPSH for these pumps. Available NPSH was determined by subtracting the suction line friction losses from the available static head. Pump performance tests verified that the available NPSH exceeds the required NPSH for rated flow conditions.

The elevation of the HPCS pump is below the water level of the suppression pool. This assures a flooded pump suction. Pump NPSH requirements are met even with the containment at atmospheric pressure by providing adequate suction head and suction line size. The LPCS pump is located in the reactor building below the water level in the suppression pool to assure positive pump suction. Pump NPSH requirements are met with the containment at atmospheric pressure. A pressure gauge is provided to indicate the suction head.

3.3 Plant Specific Confirmatory Analysis

3.3.1 Methodology

An evaluation has been performed to assess the risk associated with implementing a permanent extension of the LSCS containment Type A impact of extending the LSCS ILRT intervals from 10 years to 15 years. The risk assessment follows the guidelines from NEI 94-01 (Reference 1), the methodology outlined in Electric Power Research Institute (EPRI) TR-104285 (Reference 9) as updated by the EPRI Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals (EPRI TR-1018243) (Reference 19), the NRC regulatory guidance on the use of Probabilistic Risk Assessment (PRA) findings and risk insights in support of a request for a plant's licensing basis as outlined in RG 1.174 (Reference 5), and the methodology used for Calvert Cliffs to estimate the likelihood and risk implications of corrosion-induced leakage of steel liners going undetected during the extended test interval (Reference 20). The format of this document is consistent with the intent of the Risk Impact Assessment Template for evaluating extended integrated leak rate testing intervals provided in EPRI TR-1018243.

This analysis also provided a risk assessment of extending the plant's Drywell to Wetwell Bypass Leak Rate Test interval (DWBT) to 15 years. The DWBT risk assessment is performed in Appendix B separate from the Type A Test assessment in the main body of the calculation. The DWBT risk assessment is performed in accordance with the guidelines set forth in NEI 94-01, the methodology used in EPRI TR-1018243, and the NRC regulatory guidance on the use of Probabilistic Risk Assessment (PRA) findings and risk insights in support of a licensee request for changes to a plant's licensing basis, RG 1.174. Note the DWBT surveillance test frequency is controlled under the LSCS SFCP.

The NRC report on performance-based leak testing, NUREG-1493 (Reference 8), analyzed the effects of containment leakage on the health and safety of the public and the benefits realized from the containment leak rate testing. In that analysis, it was determined for a comparable BWR plant, that increasing the containment leak rate from the nominal 0.5 percent per day to 5 percent per day leads to a barely perceptible increase in total population exposure, and increasing the leak rate to 50 percent per day increase the total population exposure by less than 1 percent. Because ILRTs represent substantial resource expenditures, it is desirable to show that extending the ILRT interval will not lead to a substantial increase in risk from containment isolation failures to support a reduction in the test frequency for LSCS. The current analysis is being performed to confirm these conclusions based on LSCS specific PRA models and available data.

Earlier ILRT frequency extension submittals have used the EPRI TR-104285 methodology to perform the risk assessment. In October 2008, EPRI 1018243 was issued to develop a generic methodology for the risk impact assessment for ILRT interval extensions to 15 years using current performance data and risk informed guidance, primarily NRC RG 1.174. This more

recent EPRI document considers the change in population dose, large early release frequency (LERF), and containment conditional failure probability (CCFP), whereas EPRI TR-104285 considered only the change in risk based on the change in population dose. This ILRT interval extension risk assessment for LSCS employs the EPRI 1018243 methodology, with the affected System, Structure or Component (SSC) being the primary containment boundary.

In the Safety Evaluation (SE) issued by NRC letter dated June 25, 2008 (Reference 10), the NRC concluded that the methodology in EPRI TR-1009325, Revision 2, was acceptable for referencing by licensees proposing to amend their TS to extend the ILRT surveillance interval to 15 years, subject to the limitations and conditions noted in Section 4.0 of the SE. Table 3.3.1-1 addresses each of the four limitations and conditions for the use of EPRI 1009325, Revision 2.

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

	Limitation/Condition (From Section 4.2 of SE)	LSCS 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.	LSCS PRA technical adequacy is addressed in Section 3.3.2 of this submittal and Attachment 3, Risk Impact Assessment of Extending the LSCS ILRT/DWBT Interval, Appendix A, PRA Technical Adequacy, which addresses the Technical Adequacy of the PRA modeling.
2.a	The licensee submits documentation indicating that the estimated risk increase associated with permanently extending the ILRT surveillance interval to 15 years is small, and consistent with the clarification provided in Section 3.2.4.5 of this SE.	Since the ILRT extension was demonstrated to have negligible impact on CDF for LSCS, the relevant criterion is LERF. The increase in internal events LERF resulting from a change in the Type A ILRT test interval for the base case with corrosion included is 2.16E-08/year. In using the EPRI Expert Elicitation methodology, the change is estimated as 4.36E-09/year. Both of these values fall within the very small change region of the acceptance guidelines in RG 1.174. Additional details can be found in Attachment 3 of this submittal.
2.b	Specifically, a small increase in population dose should be defined as an increase in population dose of less than or equal to either 1.0 person-rem per year or 1% of the total population dose, whichever is less restrictive.	The change in dose for changing the Type A test frequency from three-per-ten years to once-per-fifteen years, measured as an increase to the total integrated dose risk for all internal events accident sequences for LSCS is 1.23E-02 person-rem/year (0.33%) using the EPRI guidance with the base corrosion included. The change in dose risk drops to 3.15E-03 person-rem/year (0.08%) when using the EPRI Expert Elicitation methodology. The values calculated per the EPRI guidance are all lower than the acceptance criteria of ≤ 1.0 person-rem/year of < 1.0% person-rem/year defined in Section 1.3 of Attachment 3 of this submittal.

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

	Limitation/Condition (From Section 4.2 of SE)	LSCS 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 frequency from the three in ten year interval to one in fifteen years including corrosion effects using the EPRI guidance is 0.99%. This value drops to 0.20% using the EPRI Expert Elicitation methodology. Both of these values are below the acceptance criteria of less than 1.5% defined in Section 1.3 of Attachment 3 of this submittal.
3.	The methodology in EPRI Report No. 1009325, Revision 2, is acceptable except for the calculation of the increase in expected population dose (per year of reactor operation). In order to make the methodology acceptable, the average leak rate 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 recommendations in the latest EPRI Report (Reference 19) and as recommended in the NRC SE (Reference 32) on this topic. It should be noted that this is more conservative than the earlier previous industry ILRT extension requests, which utilized 35 L_a for the Class 3b sequences. Additional details can be found in Attachment 3 of this submittal.
4.	A LAR is required in instances where containment over-pressure is relied upon for emergency core cooling system (ECCS) performance.	The ECCS pump specifications are such that the NPSH requirements for High Pressure Core Spray (HPCS), Low Pressure Core Spray (LPCS) and Low Pressure Core Injection (LPCI) are met with the containment atmosphere at atmospheric pressure and the suppression pool at saturation temperature. Refer to Section 3.2.6 of this submittal.

3.3.2 Technical Adequacy of the PRA

A technical PRA analysis is presented in Attachment 3, Appendix A, of this submittal to support an extension of the LSCS containment Type A integrated leak rate test (ILRT) interval to fifteen years.

PRA Model Evolution and Peer Review Summary

The 2014A versions of the LSCS PRA models are the most recent evaluations of the Unit 1 and Unit 2 risk profile at LSCS for internal event challenges. The LSCS PRA modeling is highly detailed, including a wide variety of initiating events, modeled systems, operator actions and common cause events. The PRA model quantification process used for the LSCS PRA is based on the event tree / fault tree methodology, which is a well-known methodology for the industry.

EGC employs a multi-faceted approach to establishing and maintaining the technical adequacy and plant fidelity of the PRA models for all operating EGC nuclear generation sites. This approach includes both a proceduralized PRA maintenance and update process, and the use

of self-assessments and independent peer reviews. The following information describes this approach as it applies to the LSCS PRA.

PRA Maintenance and Update

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

- Design changes and procedure changes are reviewed for their impact on the PRA model.

- Maintenance unavailabilities are captured, and their impact on CDF is trended.

- Plant specific initiating event frequencies, failure rates, and maintenance unavailabilities are updated approximately every four years.

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

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

- The approach for controlling electronic storage of Risk Management (RM) products including PRA update information, PRA models, and PRA applications.

- Guidelines for updating the full power, internal events PRA models for EGC nuclear generation sites.

- Guidance for use of quantitative and qualitative risk models in support of the On-Line Work Control Process Program for risk evaluations for maintenance tasks (corrective maintenance, preventative maintenance, minor maintenance, surveillance tests and modifications) on SSCs within the scope of the Maintenance Rule (10 CFR 50.65(a)(4)).

In accordance with this guidance, regularly scheduled PRA model updates nominally occur on the approximately 4-year cycle; longer intervals may be justified if it can be shown that the PRA adequately continues to represent the as-built, as-operated plant. The 2014A models were completed in November of 2015.

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

Plant Changes Not Yet Incorporated Into the PRA Model

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

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

Consistency with Applicable PRA Standards

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

An independent PRA peer review was conducted under the auspices of the BWR Owners Group in 2000, following the industry PRA Peer Review process. This peer review included an assessment of the PRA model maintenance and update process. The overall conclusion of the LSCS PRA Peer Review was positive, and the PRA Peer Review Team stated that the LSCS PRA can be effectively used to support applications involving risk-informed applications. The "Facts and Observations" for LSCS have been evaluated and addressed by the LSCS PRA Program as part of the last three PRA updates. There were no "A" Facts and Observations and fifteen "B" Facts and Observations identified in the 2000 PRA Peer Review report. All fifteen "B" Facts and Observations have been resolved by model changes (thirteen in the 2003 update and two in the 2011 update). No outstanding "A" or "B" priority F&Os remain.

Following the 2006C model issuance, a Peer Review of the LSCS Unit 2 PRA model was performed using the NEI 05-04 (Reference 21) process and the ASME/ANS PRA Standard (Reference 22) along with the NRC clarifications provided in RG 1.200, Revision 1 (Reference 23). This Peer Review was documented in a report dated July 2008. Of these 13 findings, 11 findings were associated with SRs that were not met. The other two findings were associated with SRs meeting CC1. Table A-1 of Attachment 3 of this submittal provides a listing of the findings related to the 11 SR 'not met' findings, the SR criteria, and resolution of the findings.

EGC has completed a self-assessment of the PRA compared with the ASME/ANS PRA Standard (Reference 22) and RG 1.200 Revision 2 (Reference 6) in preparation for the 2014 PRA update. Results of the self-assessment are shown below. Table A-2 of Attachment 3 of this Submittal provides a listing of the SRs 'not met,' the SR criteria, and the impact to the ILRT application. The results of the LSCS Self-Assessment and the resolution during the 2014 PRA update are as follows:

Number of Supporting Requirements at Capability Category II or higher or Deemed Not Applicable	309 of 326
Number of Gaps Identified for 2011A PRA (Capability Category at I or Not Met)	17
Number of Gaps Resolved for 2014 Model	8
Number of Gaps deferred, awaiting NRC or EPRI guidance or clarification, or judged to be of low Safety Significance	9

This leaves nine of the 326 Supporting Requirements that are not yet fully at Capability Category II in the latest (2014) LSCS PRA model.

- There are two (2) Supporting Requirements (DA-C6, DA-C10) that are not met.
- There are four (4) Supporting Requirements (SC-A5, HR-D3, DA-C7, DA-C8) that are met at Category I only.
- There are three (3) Supporting Requirements (IFSO-A3, IFSN-A7, IFQU-A3) which are not met, but are related to Internal Flooding, which was not within the scope of the 2014 update.

Applicability of Peer Review Findings and Observations

The remaining set of findings from the 2008 peer review and 2014 self-assessment related to the current ANS/ASME PRA Standard (Reference 22) for internal events and internal flood associated with supporting requirements that are 'not met' are described in Tables A-1 and A-2 of Appendix A of Attachment 3 of this submittal with their impact on this application noted.

External Events

Although EPRI report 1018243 (Reference 19) recommends a quantitative assessment of the contribution of external events (for example, fire and seismic) where a model of sufficient quality exists, it also recognizes that the external events assessment can be taken from existing, previously submitted and approved analyses or another alternate method of assessing an order of magnitude estimate for contribution of the external event to the impact of the changed interval. Based on this, currently available information for external events models were referenced, and a multiplier was applied to the internal events results based on the available external events information. This is further discussed in Section 5.7 of Attachment 3 of this submittal.

The current Fire PRA Model is considered adequate for risk insights, and other applications if limitations are understood and taken into account. The conservative nature of the Fire PRA modeling and the present status of the Fire PRA development lead to these limitations (See Section 5.7 of Attachment 3 of this submittal for additional details). A Fire PRA peer review was performed in December 2015. Table A-3 of Attachment 3 of this Submittal summarizes the Fire PRA Peer Review results. Table A-4 reviews and assesses the potential impact of the 19 SRs that were found to be not met at Capability Category 1 or higher. The peer review focused on compliance to the ASME/ANS standard. Although not identified by the peer review

team, there is believed to be conservatisms that can be addressed in future updates that will lead to an overall reduction in CDF contribution.

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

Seismic CDF

A LSCS seismic CDF PRA model is not maintained. As noted in Section 5.7.3 of Attachment 3 of this submittal, recent NRC work documented in Reference 27 provides seismic CDF information. The updated 2008 USGS Seismic Hazard Curves provide a weakest link CDF model. The most conservative (highest) CDF value provided in the reference document was used. The seismic CDF chosen is judged to be sufficient to support an order of magnitude LSCS ILRT external events risk impact assessment.

PRA Quality Summary

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

The 2015 Fire PRA Model results and the seismic CDF from the weakest link model using updated 2008 USGS Seismic Hazard Curves are judged to be adequate in performing a bounding "order of magnitude" assessment of ILRT impact.

Identification of Key Assumptions

The methodology employed in this risk assessment followed the EPRI guidance as previously approved by the NRC. The analysis included the incorporation of several sensitivity studies and factored in the potential impacts from external events in a bounding fashion. None of the sensitivity studies or bounding analysis indicated any source of uncertainty or modeling assumption that would have resulted in exceeding the acceptance guidelines. Since the accepted process utilizes a bounding analysis approach, which is mostly driven by that CDF contribution which does not already lead to LERF, there are no identified key assumptions or sources of uncertainty for this application (i.e., those that would not change the conclusions from the risk assessment results presented here).

Summary

A PRA technical adequacy evaluation was performed consistent with the requirements of RG 1.200, Revision 2 (Reference 6). This evaluation combined with the details of the results of this analysis demonstrates with reasonable assurance that the proposed extension to the ILRT interval for LSCS to fifteen years satisfies the risk acceptance guidelines in RG 1.174 (Reference 5).

3.3.3 Summary of Plant-Specific Risk Assessment Results

Based on the results from Section 5 of Attachment 3 of this submittal and the sensitivity calculations presented in Section 6 of Attachment 3 of this submittal, the following conclusions regarding the assessment of the plant risk are associated with permanently extending the Type A ILRT and DWBT test frequency to fifteen years:

- RG 1.174 (Reference 5) provides guidance for determining the risk impact of plant-specific changes to the licensing basis. RG 1.174 defines "very small" changes in risk as resulting in increases of CDF below 1.0E-06/year and increases in LERF below 1.0E-07/year. "Small" changes in risk are defined as increases in CDF below 1.0E-05/year and increases in LERF below 1.0E-06/year. Since the ILRT extension was demonstrated to have negligible impact on CDF for LSCS, the relevant condition is LERF. The increase in internal events LERF resulting from a change in the Type A ILRT test interval for the base case with corrosion included is 2.16E-08/year. In using the EPRI Expert Elicitation methodology, the change is estimated as 4.36E-09/year. Both of these values fall within the very small change region of the acceptance guidelines in RG 1.174.

- The change in dose risk for changing the Type A test frequency from three-per-ten years to once-per-fifteen years, measured as an increase to the total integrated dose risk for all internal events accident sequences for LSCS, is 1.23E-02 person-rem/year (0.33%) using the EPRI guidance with the base case corrosion included. The change in dose risk drops to 3.15E-03 person-rem/year (0.08%) when using the EPRI Expert Elicitation methodology. The values calculated per the EPRI guidance are all lower than the acceptance criteria of ≤ 1.0 person-rem/year of < 1.0% person-rem/year defined in Section 1.3 of Attachment 3 of this submittal.

- The increase in thee conditional containment failure frequency from the three in ten year interval to one in fifteen years including corrosion effects using the EPRI guidance is 0.99%. This value drops to 0.20% using the EPRI Expert Elicitation methodology. Both of these values are below the acceptance criteria of less than 1.5% defined in Section 1.3 of Attachment 3 of this submittal.

- To determine the potential impact from external events, a bounding assessment from the risk associated with external events was performed utilizing available information. As shown in Table 5.7-4 of Attachment 3 of this submittal, the total increase in LERF due to internal events and the bounding external events assessment is 4.15E-07/year. This value is in Region II of the RG 1.174 acceptance guidelines.

- As shown in Table 5.7-5 of Attachment 3 of this submittal, the same bounding analysis indicates that the total LERF from both internal and external risk is 6.60E-06/year which is less than the RG 1.174 limit of 1.0E-05/year given that the ΔLERF is in Region II (small change in risk).

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

- A DWBT risk analysis documented in Appendix B provides key metric values that in combination with ILRT results would not change the ILRT related conclusions described above. The DWBT values for an interval change from the original 3-in-10 years to 15 years are compared below to the ILRT base case with corrosion. These DWBT values are developed in Appendix B and reported in Appendix B, Section B.5.

Delta CDF	= 1.09E-09/yr	(ILRT increase = negligible)
Delta LERF	= 3.86E-09/yr	(ILRT increase = 2.16E-08/yr)
Delta Dose	= 1.64E-02 person-rem/yr	(ILRT increase = 1.23E-02 person-rem/yr)
Delta CCFP	= 0.01%	(ILRT increase = 0.99%)

  The DWBT CDF increase is less than 0.1% of Base CDF. The DWBT values for LERF and CCFP are significantly below the ILRT values. Although the DWBT person-rem dose rate increase is higher than the ILRT dose rate increase, the DWBT dose rate increase is approximately two orders of magnitude below the acceptance criteria of ≤ 1.0 person-rem/yr.

Therefore, increasing the ILRT and DWBT intervals on a permanent basis to a one-in-fifteen year frequency is not considered to be significant since it represents only a small change in the LSCS risk profiles.

3.3.4 Previous Assessments

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

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

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

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

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

3.4 Non-Risk Based Assessment

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

3.4.1 Appendix J Primary Containment Inspection

The purpose of this program is to perform an inspection of the Primary Containment (drywell and suppression chamber) interior and exterior surfaces and components periodically, or following extended relief valve operation. The inspection consists of a visual examination of the accessible interior and exterior surfaces of the containment system for structural problems that may affect either the containment structure leakage integrity or performance of the Type A test.

The program requires a visual inspection of the exposed accessible interior and exterior surfaces of the suppression pool and drywell to be conducted prior to initiating a Type A test and during two other refueling outages before the next Type A test if the interval for the Type A test has been extended to 10 years. This allows for early uncovering of evidence of structural deterioration.

Any irregularities such as cracking, peeling, delamination, corrosion and structural deterioration are required to be recorded and evaluated or repaired prior to the conduct of a Type A test. A general visual inspection of primary containment, exterior structure/surfaces shall also be conducted and documented. The inspection should verify no apparent changes in appearance or other abnormal degradation, i.e., widespread cracking, corrosion, spalling, and/or grease leaking.

3.4.2 Service Level I Coatings Program

The Service Level I Coatings program provides a common approach in controlling, application, maintaining and periodically assessing Service Level I Coatings. Service Level I coatings are used in areas inside the LSCS reactor containments where the coating failure could adversely affect the operation of post-accident fluid systems and thereby impair safe shutdown.

During walkdowns, coated surfaces are visually examined for any precursors to coating failure or areas that have already failed. Precursors include:

- Chalking
- Undercutting
- Sags/Runs
- Substrate Damage (surface rust, pitting, wastage, etc.)
- Discoloration/Fading
- Erosion
- Checking
- Cracking
- Wrinkling

- Flaking/Peeling/Delamination
- Blistering
- Rusting
- Mechanical Damage

3.4.3 Containment Inservice Inspection Program

The LSCS Containment ISI Plan includes ASME Section CISI Class MC pressure retaining components and their integral attachments, and CISI Class CC components and structures, and post-tensioning systems that meet the criteria of Subarticle IWA-1300. This Containment ISI Plan also includes information related to augmented examination areas, component accessibility, and examination review.

The LSCS Second Interval Containment Inservice Inspection Program Plan was developed in accordance with the requirements of 10 CFR 50.55a including all published changes through September 30, 2006 and the 2001 Edition through the 2003 Addenda of ASME Section XI, subject to the limitations and modifications contained within Paragraph (b) of the regulation. The Second CISI Interval spans from October 1, 2007 to September 30, 2017. These limitations and modifications are detailed as follows:

10 CFR 50.55a(b)(2)(viiii)(E) – *Examination of concrete containments*

For Class CC applications, the licensee shall evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of or result in degradation to such inaccessible areas. For each inaccessible area identified, the licensee shall provide the following in the ISI Summary Report required by IWA-6000:

(1) A description of the type and estimated extent of degradation, and the conditions that led to the degradation
(2) An evaluation of each area, and the result of the evaluation and;
(3) A description of necessary corrective actions

10 CFR 50.55a(b)(2)(viii)(F) – *Examination of concrete containments*

Personnel that examine containment concrete surfaces and tendon hardware, wires or strands must meet the qualification provisions in IWA-2300. The "owner-defined" personnel qualification provisions in IWL-2310(d) are not approved for use.

10 CFR 50. 55a(b)(2)(viii)(G) – *Examination of concrete containments*

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

10 CFR 50.55a(b)(2)(ix)(A) – *Examination of metal containments and the liners of concrete containments*

For Class MC applications, the licensee shall evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of or result in

degradation to such inaccessible areas. For each inaccessible area identified, the licensee shall provide the following in the ISI summary report as required by IWA-6000:

(1) A description of the type and estimated extent of degradation, and the conditions that led to the degradation;
(2) An evaluation of each area, and the result of the evaluation, and;
(3) A description of necessary corrective actions

10 CFR 50.55a(b)(2)(ix)(B) – *Examination of metal containments and the liners of concrete containments*

When performing remotely the visual examinations required by Subsection IWE the maximum direct examination distance specified in Table IWA-2210-1 may be extended and the minimum illumination requirements specified in Table IWA-2210-1 may be decreased provided that the conditions or indications for which the visual examination is performed can be detected at the chosen distance and illumination.

10 CFR 50.55a(b)(2)(ix)(F) – *Examination of metal containments and the liners of concrete containments*

VT-1 and VT-3 examinations must be conducted in accordance with IWA-2200. Personnel conducting examinations in accordance with the VT-1 or VT-3 examination method shall be qualified in accordance with IWA-2300. The "owner-defined" personnel qualification provisions in IWE-2330(a) for personnel that conduct VT-1 and VT-3 examinations are not approved for use.

10 CFR 50.55a(b)(2)(ix)(G) – *Examination of metal containments and the liners of concrete containments*

The VT-3 examination method must be used to conduct the examinations in Items E1.12 and E1.20 of Table IWE 2500-1. An examination of the pressure-retaining bolted connections in Item E1.11 of Table IWE-2500-1 using the VT-3 examination method must be conducted once each interval. The "owner-defined" visual examination provisions in IWE-2310(a) are not approved for use for VT-1 and VT-3 examinations.

10 CFR 50.55(a)(b)(2)(ix)(H) - *Examination of metal containments and the liners of concrete containments*

Containment bolted connections that are disassembled during the scheduled performance of the examinations in Item E1.11 of Table IWE-2500-1 must be examined using the VT-3 examination method. Flaws or degradation identified during the performance of a VT-3 examination must be examined in accordance with the VT-1 examination method. The criteria in the material specification or IWB-3517.1 must be used to evaluate containment bolting flaws or degradation. As an alternative to performing VT-3 examinations of containment bolted connections that are disassembled during the scheduled performance of Item E1.11, VT-3 examinations of containment bolted connections may be conducted whenever containment bolted connections are disassembled for any reason.

10 CFR 50.55(a)(b)(2)(ix)(I) – *Examination of metal containments and the liners of concrete containments*

The ultrasonic examination acceptance standard specified in IWE-3511.3 for Class MC pressure –retaining components must also be applied to metallic liners of Class CC pressure-retaining components.

Augmented Examination Areas

Metal containment components potentially subject to augmented examination per paragraph IWE-1240 have been evaluated in the containment sections of the ISI Classification Basis Document. These sections define the areas that are subjected to augmented examination.

Similarly, concrete surfaces may be subject to Detailed Visual examination in accordance with Paragraph IWL-2310, if declared to be 'Suspect Areas' by the examiner or the Responsible Engineer.

No significant conditions were identified in the First CISI Interval and no significant conditions are currently identified in the Second Interval as requiring application of additional augmented examination requirements under Paragraph IWE-1240 or IWL-2310.

Component Accessibility

CISI Class MC pressure retaining components subject to examination shall remain accessible for either direct or remote visual examination from at least one side per the requirements of ASME Section XI, Paragraph IWE-1230.

Paragraph IWE-1231(a)(3) requires 80% of the pressure-retaining boundary to remain accessible for either direct or remote visual examination, from at least one side of the vessel, for the life of the plant.

Portions of components embedded in concrete or otherwise made inaccessible during construction are exempted from examination, provided that the requirements of ASME Section XI, Paragraph IWE-1232 have been fully satisfied.

In addition, inaccessible surface areas exempted from examination include those surface areas where visual access by line of sight with adequate lighting from permanent vantage points is obstructed by permanent plant structures, equipment, or components; provided these surface areas do not require examination in accordance with the inspection plan, or augmented examination in accordance with Paragraph IWE-1240.

Responsible Individual and Engineer

ASME Section XI Subsection IWE requires the Responsible Individual to be involved in the development, performance, and review of the CISI examinations. The Responsible Individual shall meet the requirements of ASME Section XI, Paragraph IWE-2320.

ASME Section XI Subsection IWL requires the Responsible Engineer to be involved in the development, approval, and review of the CISI examinations. The Responsible Engineer shall meet the requirements of ASME Section XI, Paragraph IWL-2320.

Inspection Periods

First Interval CISI Program

CISI examinations were originally invoked by amended regulations contained within a Final Rule issued by the NRC. The amended regulation incorporated the requirements of the 1992 Edition through the 1992 Addenda of ASME Section XI, Subsections IWE and IWL, subject to the specific modifications that were included in Paragraphs 10 CFR 50.55a(b)(2)(ix) and 10 CFR 50.55a(b)(2(x). Relief from the examination requirements of the 1992 Edition through the 1992 Addenda of ASME Section XI was granted by the NRC to allow LSCS to use the 1998 Edition, No Addenda for inspection of containment components.

The final rulemaking was published in the Federal Register on August 8, 1996 and specified an effective date of September 9, 1996. Implementation of the Subsection IWE and IWL Program from a scheduling standpoint was driven by the five year expedited implementation period per 10 CFR 50.55a(g)(6)(ii)(B), which specified that the examinations required to be completed by the end of the first period of the First Inspection Interval (per Table IWE-2412-1) be completed by the effective date (by September 9, 2001).

ASME Section XI Subsections IWE, IWL, approved ASME IWE/IWL Code Cases, and approved alternatives through related relief requests and SEs were added to the ISI Program midway through the Second ISI Interval to address CISI. The First CISI Interval was initially scheduled from September 9, 1996 through September 9, 2008 for both LSCS Units 1 and 2.

The CISI Program Plan was developed and implemented prior to the required date, and examinations for the first, second, and third periods were performed in accordance with the First CISI Interval schedule for LSCS Units 1 and 2. As detailed in Section 1.4, the transition from the First to Second Interval CISI Program occurred approximately one year early for LSCS Units 1 and 2 to allow for a common interval date and Code of record between the ISI and CISI Programs.

To effect the synchronization and alignment between the LSCS Units 1 and 2 ISI and CISI intervals, Paragraph IWA-2430(d) was used to adjust each inspection interval within the one year allowance. Since the provisions of ASME Section XI Paragraph IWA-2430(d) were adhered to as required, a relief request was not necessary.

LSCS informed the NRC by letter on September 22, 2006 of this synchronization permitting the subsequent ISI and CISI Programs to share a common inspection interval start and end date to implement common Code Editions for ISI Class 1, 2, 3, MC and CC components. As such, the LSCS Units 1 and 2 First CISI Interval was effective from September 9, 1996 through September 30, 2007.

Second Interval CISI Program

Pursuant to 10 CFR 50.55a(g), licensees are required to update their CISI Programs to meet the requirements of ASME Section XI once every ten years or inspection interval. The CISI Program is required to comply with the latest Edition and Addenda of ASME Section XI incorporated by reference in 10 CFR 50.55a twelve months prior to the start of the interval per 10 CFR 50.55a(g)(4)(ii). As discussed in Section 1.6 above, the start of the Second CISI Interval will be on October 1, 2007 for LSCS Units 1 and 2. Based on this date, the latest

Edition and Addenda of ASME Section XI referenced in 10 CFR 50.55a(b)(2) twelve months prior was the 2001 Edition through the 2003 Addenda.

The LSCS Second Interval CISI Program Plan was developed in accordance with the requirements of 10 CFR 50.55a including all published changes through September 3, 2006, and the 2001 Edition through the 2003 Addenda of ASME Section XI, subject to the limitations and modifications contained within Paragraph (b) of the regulation.

The CISI Program Plan addresses Subsections IWE, IWL, approved ASME IWE/IWL Code Cases, approved alternatives through related relief requests and SERs and utilizes Inspection Program B as defined therein.

The LSCS Third Interval CISI Program Plan is currently in development and has not been approved by the NRC to date.

<table>
<tr><th colspan="7">Table 3.4.3-1 – Class MC Component Examinations</th></tr>
<tr><th colspan="2">Unit 1</th><th>Period</th><th>Interval</th><th>Period</th><th colspan="2">Unit 2</th></tr>
<tr><td>Outage Number</td><td>Projected Outage Start Date or Outage Duration</td><td>Start Date to End Date</td><td>Start Date to End Date</td><td>Start Date to End Date</td><td>Projected Outage Start Date or Outage Duration</td><td>Outage Number</td></tr>
<tr><td>L1R13</td><td>Scheduled February 2010</td><td>First 10/1/2007 to 9/30/2010</td><td rowspan="5">Second (Unit 1) 10/1/2007 to 9/30/2017[1]
Second (Unit 2) 10/1/2007 to 9/30/2017[1]</td><td>First 10/1/2007 to 9/30/2010</td><td>Scheduled March 2009</td><td>L2R12</td></tr>
<tr><td>L1R14</td><td>Scheduled February 2012</td><td rowspan="2">Second 10/1/2010 to 9/30/2014</td><td rowspan="2">Second 10/1/2010 to 9/30/2014</td><td>Scheduled March 2011</td><td>L2R13</td></tr>
<tr><td>L1R15</td><td>Scheduled February 2014</td><td>Scheduled March 2013</td><td>L2R14</td></tr>
<tr><td rowspan="2">L1R16</td><td rowspan="2">Scheduled February 2016</td><td rowspan="2">Third 10/1/2014 to 9/30/2017</td><td rowspan="2">Third 10/1/2014 to 9/30/2017</td><td>Scheduled March 2015</td><td>L2R15</td></tr>
<tr><td>Scheduled March 2017</td><td>L2R16</td></tr>
</table>

Note 1: The First CISI Intervals for Units 1 and 2 were reduced by 345 days as permitted by Paragraph IWA-2430(d). This reduction is being carried forward to the Second CISI Intervals to facilitate the CISI Program sharing common interval start dates, end dates and codes of record with the ISI Program. This means that the end of the Second CISI Interval can only be moved forward another 20 days or extended out up to one year under Paragraph IWA-2430(d). Note that this reduction is separate from and in addition to that of Paragraph IWA-2430(e) which requires the successive interval pattern to be adjusted accordingly.

<table>
<tr><th colspan="7">Table 3.4.3-2 – Class CC-Concrete Component Examinations</th></tr>
<tr><th colspan="2">Unit 1</th><th>Period</th><th>Interval</th><th>Period</th><th colspan="2">Unit 2</th></tr>
<tr><td>Outage Number</td><td>Projected Outage Start Date or Outage Duration</td><td>Start Date to End Date</td><td>Start Date to End Date</td><td>Start Date to End Date</td><td>Projected Outage Start Date or Outage Duration</td><td>Outage Number</td></tr>
<tr><td>L1R12</td><td>Scheduled February 2008</td><td>No Section XI Exams</td><td rowspan="5">Second (Unit 1) 10/1/2007 to 9/30/2017[1]

Second (Unit 2) 10/1/2007 to 9/30/2017[1]</td><td>No Section XI Exams</td><td>Scheduled March 2009</td><td>L2R12</td></tr>
<tr><td>L1R13</td><td>Scheduled February 2010</td><td>30th - 9/15/2009 (9/15/2008 to 9/14/2010)[2]</td><td>25th - 9/18/2010 (9/18/2009 to 9/17/2011)[2]</td><td>Scheduled March 2011</td><td>L2R13</td></tr>
<tr><td>L1R14</td><td>Scheduled February 2012</td><td>No Section XI Exams</td><td>No Section XI Exams</td><td>Scheduled March 2013</td><td>L2R14</td></tr>
<tr><td>L1R15</td><td>Scheduled February 2014</td><td>35th 9/15/14 (9/15/13 to 9/14/15)[2]</td><td>30th - 9/18/2015 (9/18/2014 to 9/17/2016)[2]</td><td>Scheduled March 2015</td><td>L2R15</td></tr>
<tr><td>L1R16</td><td>Scheduled February 2016</td><td>No Section XI Exams</td><td>No Section XI Exams</td><td>Scheduled March 2017</td><td>L2R16</td></tr>
</table>

Note 1: The First CISI Intervals for Units 1 and 2 were reduced by 345 days as permitted by Paragraph IWA-2430(d). This reduction is being carried forward to the Second CISI Intervals to facilitate the CISI Program sharing common interval start dates, end dates and codes of record with the ISI Program. This means that the end of the Second CISI Interval can only be moved forward another 20 days or extended out up to one year under Paragraph IWA-2430(d). Note that this reduction is separate from and in addition to that of Paragraph IWA2430(e) which requires the successive interval pattern to be adjusted accordingly.

Note 2: The Subsection IWL inspection schedule for the concrete containment surface meets the requirements of IWL-2400. IWL-2510 inspections will be performed once every 5 years. They will begin not more than 1 year prior to the specified date and will be completed not more than 1 year after such date. The initial Subsection IWL concrete examinations for each unit were required to be completed between September 9, 1996 and September 8, 2001 by 10 CFR 50.55a. The rolling 5 year examination date and associated 2 year window for each unit is determined from these first inspection dates (9/15/99 and 9/18/00 for Units 1 and 2 respectively).

<table>
<tr><th colspan="7">Table 3.4.3-3 – Class CC-Tendon Examinations</th></tr>
<tr><th colspan="2">Unit 1</th><th>5-Year Period</th><th>Interval</th><th>Period</th><th colspan="2">Unit 2</th></tr>
<tr><td>Outage Number</td><td>Projected Outage Start Date or Outage Duration</td><td>Exam # - Date (2 Year Window)</td><td>Start Date to End Date</td><td>Exam # - Date (2 Year Window)</td><td>Projected Outage Start Date or Outage Duration</td><td>Outage Number</td></tr>
<tr><td>L1R12</td><td>Scheduled February 2008</td><td>30th - 12/1/08 (12/1/07 to 11/30/09)[2]</td><td rowspan="5">Second (Unit 1) 10/1/2007 to 9/30/2017[1]

Second (Unit 2) 10/1/2007 to 9/30/2017[1]</td><td>25th - 6/1/08 (6/1/07 to 5/31/09)[2]</td><td>Scheduled March 2009</td><td>L2R12</td></tr>
<tr><td>L1R13</td><td>Scheduled February 2010</td><td rowspan="2">No Section XI Exams</td><td>No Section XI Exams</td><td>Scheduled March 2011</td><td>L2R13</td></tr>
<tr><td>L1R14</td><td>Scheduled February 2012</td><td>30th - 6/1/13 (6/1/12 to 5/31/14)[2]</td><td>Scheduled March 2013</td><td>L2R14</td></tr>
<tr><td>L1R15[3]</td><td>Scheduled February 2014</td><td>35th - 12/1/13 (12/1/12 to 11/30/14)[2]</td><td rowspan="2">No Section XI Exams</td><td>Scheduled March 2015</td><td>L2R15</td></tr>
<tr><td>L1R16</td><td>Scheduled February 2016</td><td>No Section XI Exams</td><td>Scheduled March 2017</td><td>L2R16</td></tr>
</table>

Note 1: The First CISI Intervals for Units 1 and 2 were reduced by 345 days as permitted by Paragraph IWA-2430(d). This reduction is being carried forward to the Second CISI Intervals to facilitate the CISI Program sharing common interval start dates, end dates, and codes of record with the ISI Program. This means that the end of the Second ISI Interval can only be moved forward another 20 days or extended out up to one year under Paragraph IWA-2430(d). Note that this reduction is separate from and in addition to that of Paragraph IWA-2430(e) which requires the successive interval pattern to be adjusted accordingly.

Note 2: The Subsection IWL inspection schedule for the containment post-tensioning system meets the requirements of Subarticle IWL-2400. Paragraph IWL-2520 inspections will be performed once every five years. They will begin not more than 1 year prior to the specified date and will be complemented not more than 1 year after such date. The initial Subsection IWL five-year examination date for each unit was determined based on the previous inspection dates under the Station Tendon Surveillance program prior to Subsection IWL being endorsed by the NRC. These original dates were based on the initial SIT tests.

Note 3: ASME Section XI Item Number L2.10 tests and L2.20 examinations are performed during this outage. These tests and examinations are performed every other 5-year period for each individual Unit such that the two Units alternate every five years (See Relief Request I3R-05).

Components Subject to Examination

Table 3.4.3-4 – Unit 1& Common Inservice Inspection Summary						
Examination Category	**Item Number**	**Description**	**Exam Requirements**	**Total Number of Components**	**Relief Request**	**Notes**
E-A Containment Surfaces	E1.11	Containment Vessel Pressure Retaining Boundary - Accessible Surface Areas	General Visual	293	N/A	7
	E1.11	Containment Vessel Pressure Retaining Boundary - Bolted Connections, Surfaces	Visual, VT-3	64	N/A	7
	E1.12	Containment Vessel Pressure Retaining Boundary - Wetted Surfaces of Submerged Areas	Visual, VT-3	9	N/A	8
	E1.20	Containment Vessel Pressure Retaining Boundary - BWR Vent System Accessible Surface Areas	Visual, VT-3	154	N/A	8
E-C Containment Surfaces Requiring Augmented Examination	E4.11	Containment Surface Areas - Visible Surfaces	Visual, VT-1	0	N/A	9
	E4.12	Containment Surface Areas-Surface Area Grid Minimum Wall Thickness Locations	Ultrasonic Thickness	0	N/A	10

Table 3.4.3-5 – Unit 2 Inservice Inspection Summary						
Examination Category	**Item Number**	**Description**	**Exam Requirements**	**Total Number of Components**	**Relief Request**	**Notes**
E-A Containment Surfaces	E1.11	Containment Vessel Pressure Retaining Boundary - Accessible Surface Areas	General Visual	293	N/A	7
	E1.11	Containment Vessel Pressure Retaining Boundary - Bolted Connections, Surfaces	Visual, VT-3	64	NA	7
	E1.12	Containment Vessel Pressure Retaining Boundary - Wetted Surfaces of Submerged Areas	Visual, VT-3	9	N/A	8
	E1.20	Containment Vessel Pressure Retaining Boundary - BWR Vent System Accessible Surface Areas	Visual, VT-3	154	N/A	8
E-C Containment Surfaces Requiring Augmented Examination	E4.11	Containment Surface Areas - Visible Surfaces	Visual, VT-1	0	N/A	9
	E4.12	Containment Surface Areas-Surface Area Grid Minimum Wall Thickness Locations	Ultrasonic Thickness	0	N/A	10

Table 3.4.3-6 – Unit 1 & Common Inservice Inspection Summary						
Examination Category	**Item Number**	**Description**	**Exam Requirements**	**Total Number of Components**	**Relief Request**	**Notes**
L-A Concrete Surfaces	L1.11	Concrete Surfaces - All Accessible Surface Areas	General Visual	24	N/A	
	L1.12	Concrete Areas - Suspect Areas (No Suspect Areas Identified)	Detailed Visual	0	N/A	
L-B Unbonded Post-Tensioning System	L2.10	Tendon	IWL-2522	307	I3R-05	
	L2.20	Tendon - Wire or Strand	IWL-2523.2	0	I3R-05	
	L2.30	Tendon - Anchorage Hardware and Surrounding Concrete	Detailed Visual	614	N/A	
	L2.40	Tendon - Corrosion Protection Medium	IWL-2525.2(a)	0	N/A	
	L2.50	Tendon - Free Water	IWL-2525.2(a)	0	N/A	

Table 3.4.3-7 – Unit 1 & Common Inservice Inspection Summary						
Examination Category	**Item Number**	**Description**	**Exam Requirements**	**Total Number of Components**	**Relief Request**	**Notes**
L-A Concrete Surfaces	L1.11	Concrete Surfaces - All Accessible Surface Areas	General Visual	24	N/A	
	L1.12	Concrete Areas - Suspect Areas (No Suspect Areas Identified)	Detailed Visual	0	N/A	
L-B Unbonded Post-Tensioning System	L2.10	Tendon	IWL-2522	308	I3R-05	
	L2.20	Tendon - Wire or Strand	IWL-2523.2	0	I3R-05	
	L2.30	Tendon - Anchorage Hardware and Surrounding Concrete	Detailed Visual	616	N/A	
	L2.40	Tendon - Corrosion Protection Medium	IWL-2525.2(a)	0	N/A	
	L2.50	Tendon - Free Water	IWL-2525.2(a)	0	N/A	

Note 7: Bolted connections examined per Item Number E1.11 require a General Visual examination each period and a VT-3 visual examination once per interval and each time the connection is disassembled during a scheduled Item Number E1.11 examination. Additionally, a VT-1 visual examination shall be performed if degradation or flaws are identified during the VT-3 examination. These modifications are required by 10 CFR 50.55a(b)(2)(ix)(G) and 10 CFR 50.55a(b)(2)(ix)(H). This note superseded by 10 CFR 50.55a(b)(2)(ix)(H) dated July 21, 2011.

Note 8: Item Numbers E1.12 and E1.20 require VT-3 visual examination in lieu of General Visual examination, as modified by 10 CFR 50.55a(b)(2)(ix)(G).

Note 9: Item Number E4.11 requires VT-1 visual examination in lieu of Detailed Visual examination, as modified by 10 CFR 50.55a(b)(2)(ix)(G).

Note 10: The ultrasonic examination acceptance standard specified in Paragraph IWE-3511.3 for CISI Class MC pressure-retaining components must also be applied to metallic liners of CISI Class CC pressure-retaining components, as modified by 10 CFR 50.55a(b)(2)(ix)(I).

3.4.4 Supplemental Inspection Requirements

With the implementation of the proposed change, TS 5.5.13 will be revised by replacing the reference to RG 1.163 (Reference 4) with reference to NEI 94-01, Revision 3-A (Reference 1). This will require that a general visual examination of accessible interior and exterior surfaces of the containment for structural deterioration that may affect the containment leak-tight integrity be conducted. This inspection must be conducted prior to each Type A test and during at least three other outages before the next Type A test if the interval for the Type A test has been extended to 15 years in accordance with the following sections of NEI 94-01, Revision 3-A:

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

In addition to the IWE and IWL examinations scheduled in accordance with the Containment Inservice Inspection Program, the performance of inspections in accordance with the Appendix J Primary Containment Inspection (Reference Section 3.4.1 of this submittal) will be utilized to ensure compliance with the visual inspection requirements of TS SR 3.6.1.1.1, and NEI 94-01 Revision 3-A.

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

LSCS Types B and C testing program requires testing of electrical penetrations, airlocks, hatches, flanges, and containment isolation valves in accordance with 10 CFR Part 50, Appendix J, Option B, and RG 1.163. The results of the test program are used to demonstrate that proper maintenance and repairs are made on these components throughout their service life. The Types B and C testing program provides a means to protect the health and safety of plant personnel and the public by maintaining leakage from these components below appropriate limits. In accordance with TS 5.5.13, the containment leakage rate, as determined by totaling the leakages of all Type B and Type C LLRTs (exclusive of the main steam lines and personnel access door seals), must be less than or equal to 0.6 L_a or 384.2 standard cubic ft per hour (SCFH).

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

Tables 3.4.5-1 and 3.4.5-2 provide local leak rate test (LLRT) data trend summaries for LSCS since 2005.

This summary demonstrates a history of satisfactory Type B and Type C tested component performance from the 2005 through the 2016 inclusive of the most recent ILRTs for LSCS, Units 1 and 2.

Table 3.4.5-1 – LSCS Unit 1 Type B and C LLRT Combined As-Found/As-Left Trend Summary						
RFO	**2006**	**2008**	**2010**	**2012**	**2014**	**2016**
	L1R11	**L1R12**	**L1R13**	**L1R14**	**L1R15**	**L1R16**
AF Min Path (SCFH)	122.01	88.98	106.54	104.31	115.88	169.34
Fraction of 0.6 L_a (percent)	52.73%	38.45%	46.04%	28.66%	31.84%	46.52%
AL Max Path (SCFH)	145.81	160.06	187.49	206.39	192.03	221.08
Fraction of 0.6 L_a (percent)	63.01%	69.17%	81.02%	56.70%	52.76%	60.74%
AL Min Path (SCFH)	80.79	78.21	72.25	101.23	115.55	112.97
Fraction of 0.6 L_a (percent)	34.91%	33.80%	31.22%	27.81%	31.74%	31.04%

Table 3.4.5-2 – LSCS Unit 2 Type B and C LLRT Combined As-Found/As-Left Trend Summary						
RFO	**2005**	**2007**	**2009**	**2011**	**2013**	**2015**
	L2R10	**L2R11**	**L2R12**	**L2R13**	**L2R14**	**L2R15**
AF Min Path (SCFH)	106.90	56.61	85.17	92.56	110.37	148.72
Fraction of 0.6 L_a (percent)	46.20%	24.46%	36.80%	25.40%	30.32%	38.71%
AL Max Path (SCFH)	173.17	125.11	136.35	150.35	160.93	214.14
Fraction of 0.6 L_a (percent)	74.84%	54.10%	58.92%	41.26%	44.21%	55.74%
AL Min Path (SCFH)	73.99	55.80	62.25	77.14	73.38	117.98
Fraction of 0.6 L_a (percent)	31.97%	24.11%	26.90%	21.17%	20.16%	30.71%

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

Tables 3.4.5-3 and 3.4.5-4 identify the components that were on extended LLRT intervals and have not demonstrated acceptable performance during the previous two outages for LSCS Units 1 and 2:

Table 3.4.5-3 – LSCS Unit 1 Type B and C LLRT Program Implementation Review						
L1R15 - 2014						
Component	**As-Found SCFH**	**Admin Limit SCFH**	**As-Left SCFH**	**Cause of Failure**	**Corrective Action**	**Scheduled Interval**
1E12-F008	596	30	1.05	Actuator Failure	Replaced Actuator	30 Months
1PC002A	98.5	10	12 (1)	Flange Leakage	Tightened Flange bolts	30 Months
L1R16 2016						
Component	**As-Found SCFH**	**Admin Limit SCFH**	**As-Left SCFH**	**Cause of Failure**	**Corrective Action**	**Scheduled Interval**
1E51-F086	Would Not Pressurize (2)	10	1.75	Valve Seating Issue	Rebuilt Valve	30 Months
1C51-J004E	19.8	10	19.8	(3)	(3)	30 Months

Note 1: The Drywell to Suppression Pool Vacuum Breaker Manual Isolation Valve 1PC002A outboard flange is not equipped with a locally testable seal. Testing the outboard flange requires pressurizing the entire vacuum breaker line and performing the qualitative soap bubble test.

Note 2: Minimum pathway leakage measured at 1.75 SCFH through outboard containment isolation valve 1E51-F080.

Note 3: As-Found measured leakage for 1C51-J004 absorbed into leakage totals for L1R16. Valve is planned for replacement during L1R17.

Table 3.4.5-4 – LSCS Unit 2 Type B and C LLRT Program Implementation Review						
L2R14 - 2013						
Component	As-Found SCFH	Admin Limit SCFH	As-Left SCFH	Cause of Failure	Corrective Action	Scheduled Interval
None(3)						
L2R15 - 2015						
Component	As-Found SCFH	Admin Limit SCFH	As-Left SCFH	Cause of Failure	Corrective Action	Scheduled Interval
2RF-012/13	17.2	10	3.6	Valve Seat	Machined Seat	30 Months
2C51-J004C	15.5	10	15.5	(4)	(4)	30 Months

Note 3: There were no administrative failures associated with components on extended intervals identified in L2R14.

Note 4: As-Found measured leakage for 2C51-J004 absorbed into leakage totals for L2R15. Valve is planned for replacement during L2R16.

3.5 Operating Experience

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

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

- Information Notice (IN) 92-20, "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 or Liner Moisture Barrier Inspection"

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

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

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

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

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

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

Discussion:

The components and testing configurations described in IN 92-20 are not applicable to the LSCS Appendix J Testing Program.

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

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

Discussion:

The LSCS design, a Mark II BWR with no moisture barrier, eliminates many of the corrosion paths referenced in IN 2004-09. The outside face of the drywell liner does not include an air gap between the liner and the concrete. The liner served as a form for the concrete during construction. Drywell liner plate corrosion on the outside face is not expected in the oxygen-starved environment.

The LSCS design does not utilize a moisture barrier at the concrete to steel liner interface. The interface is inspected by both the IWE and the IWL program requirements.

Reactor Cavity leakage at LSCS has been periodically identified only during refueling outages and then, not during every refuel outage. The source of the leakage has not been positively identified. The water is clean, non-borated water, difficult to quantify, and estimated at less than 12 ounces per hour. An existing IWE program enhancement to perform ultrasonic thickness measurements on the Unit 2 drywell liner in the vicinity of the observed exterior concrete seepage has produced over 200 UT measurements since 1999, with no liner plate thinning detected.

3.5.3 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. However, 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:

LSCS is a BWR in which the drywell is inerted during operation. While surface corrosion has been identified, it has been associated with damage to coatings in the maintenance process or as a result of modifications. These have been typically repaired at the next available refueling outage. Informed thinking based on industry experience and corrosion rates has concluded that corrosion caused by organic FME material during concrete pours would have revealed itself after more than 30 years.

3.5.4 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 system in accordance with the ASME Code Section XI, Subsection IWE, as required by 10 CFR 50.55a(g)(4).

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

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

Discussion:

LSCS has submerged leak channel systems that are of a different design and material (stainless steel) than those identified in the IN and are not susceptible to the accelerated corrosion degradation and aging effects identified.

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

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

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:

LSCS Mark II Primary Containment design does not include a moisture barrier as shown in ASME Section XI, Figure 2500-1 of RIS 2016-07.

3.5.6 Primary Containment IWE Operating Experience Since Completion of Last ILRTs

<u>L1R16 Refueling Outage (2016) Coatings Inspections</u>

During L1R16, a coating assessment of the Unit 1 Primary Containment was performed. Locations inspected included the drywell, drywell head, and suppression pool vapor region. Protective coatings in the drywell and the drywell head generally consist of Carbozinc 11, inorganic zinc primer with an epoxy topcoat. The coatings in the suppression pool are Carbozinc 11 inorganic zinc. Inspection and assessment of the Service Level I protective coatings include:

- Visual inspection of coating condition to identify and characterize apparent coating defects
- Visual inspection of exposed substrate (if any) to assess corrosion conditions
- Assessment of all available and accessible coated surfaces including concrete floors, steel liner plate, structural steel, stairway and landing, piping, tanks, systems and components (valves, vessels and pumps), and miscellaneous equipment

During the L1R16 refueling outage, all elevations of the drywell interior and exterior drywell head cover were inspected and assessed to identify areas of deteriorated coatings. Areas identified in the previous coating evaluation were repaired in accordance with LSCS procedures and specifications. There was a minor amount of damage to the liner plate coating due to scaffolding poles impact hitting the liner coating during outages. The coatings related work is for "spot repairs" in accessible areas that are available for the coatings repair contractors. Not all areas are accessible due to dose/ALARA i.e., fuel moves, equipment repair activities, and "spot repairs" are typically completed every refuel outage.

Inspection Findings:

Unit 1 Drywell Elevation 740 ft Equipment Hatch Cover 235 degrees

The condition of protective coatings on the hatch cover had not changed significantly since the previous assessments. The appearance was typical of age related mechanical damage. Areas on the hatch cover bolt connections exhibited missing topcoat. The primer in most locations appeared to be generally intact with areas of missing primer due to wear from bolts and washers. There did not appear to be any active substrate corrosion.

The personnel hatch located at 125 degree azimuth had damage to coating on liner due to wear and impacts. Most of the damage was located on the inner air lock. Areas of coating damage down to primer were also observed on the personnel hatch door.

Unit 1 Drywell Elevation 740 ft Liner

The liner of elevation 740 ft of the drywell had damage due to outage activities, such as welding, grinding and personnel impact. The damage consisted of areas damaged to substrate, areas of topcoat removal and areas where the coating was burned. Generally, the liner coating system was in good condition. No end of service life or aging areas, such as cracking and dis-bondment were observed on the 740' elevation. These locations will be repaired in the future L1R17 with coatings related work orders. The locations for repair are prioritized due to accessibility, dose and other work control factors.

Unit 1 Drywell Liner Elevation 767 ft and 777 ft

The coating condition on elevation 777 ft of the drywell was similar to elevation 740 ft. There was some minor damage of the topcoat to the primer. In general, the overall protective coatings on this elevation appeared to be in good condition. Most of the damage found was due to worker activity.

Unit 1 Drywell Liner Elevation 796 ft

The coating condition on elevation 796 ft of the drywell was similar to elevation 740 ft. There was minor mechanical damage of the topcoat to the primer. In general, the coatings on this elevation appeared to be in good condition.

Unit 1 Drywell Liner Elevation 807 ft

The protective coatings on elevation 807 ft were generally in good condition. A few areas of minor damage were present. The majority of the damaged areas were to primer only. The areas of damage to the substrate area minor and exhibited no corrosion.

Unit 1 Suppression Pool

Inspection of the Unit 1 suppression pool was limited due to access restrictions. There is no catwalk in the suppression pool; therefore, inspection was limited to areas observed from a small platform located at 210 degree azimuth. The suppression pool liner is stainless steel, and corrosion is not possible. The supports for the downcomers, struts, and piping are carbon

steel coated with Carbozinc 11, inorganic zinc. Overall, the inorganic zinc appeared to be in good condition with isolated areas of light surface corrosion.

Drywell Head Cover

The exterior upper surface of the drywell head cover exhibited areas of some loose and flaking topcoat with the inorganic zinc primer intact. The entire lower bottom near and around bolt connections had widespread minor damage from installing and tightening of the bolts. The interior of the drywell head is in good condition, with just a few minor areas of flaking top coat and minor areas of damage. These damaged areas probably occurred during the removal of the drywell head cover.

<u>L2R15 Refueling Outage (2015) Coatings Inspections</u>

During L2R15, a coating assessment of the Unit 2 Primary Containment was performed. Locations inspected included the drywell, drywell head, and suppression pool. Protective coatings in the drywell and the drywell head generally consist of Carbozinc 11, inorganic zinc primer with an epoxy topcoat. The coatings in the suppression poll are Carbozinc 11 inorganic zinc. Inspection and assessment of the Service Level I protective coatings included:

- Visual inspection of coating conditions to identify and characterize apparent coating defects
- Visual inspection of exposed substrate (if any) to assess corrosion conditions
- Assessment of all available and accessible coated surfaces including concrete floors, concrete walls, steel liner plate, structural steel, stairways and landings, piping, tanks, systems and components (valves, vessels and pumps), and miscellaneous equipment

Inspection Findings:

Unit 2 Drywell Elevation 740 ft Equipment Hatch Cover

The condition of the protective coatings on the hatch cover had not changed significantly since the previous assessments. The appearance was typical of age related mechanical damage. Areas on the hatch cover bolt connections exhibited missing topcoat. The primer in most locations was present and appeared to be intact with areas of missing primer due to wear of bolts and washers. There did not appear to be any active substrate corrosion. Scratches and mechanically damaged areas were repaired during L2R15.

Unit 2 Drywell Elevation 740 ft Liner

The liner on elevation 740 ft of the drywell had mechanical damage due to scaffold poles and insulation hitting the wall. The mechanical damage consisted of areas that were to substrate and areas that only removed the topcoat. During prior outages, the inorganic zinc primer was intact in most areas where the topcoat was delaminating. A larger area approximately 3 in x 18 in of topcoat delamination was identified and repaired with Keeler & Long 65847107 Epoxy. This area was located at 260 degree azimuth.

The plan during the L2R15 refueling outage was to identify areas where the substrate was exposed. Areas to substrate were evaluated and coating repair performed prior to returning to service. The majority of the coating deficiencies were to primer coat only and can be repaired during the next few refueling outages. This area was not repaired due to ALARA reasons, and these locations will be repaired in the future L2R17 with coatings related coatings work orders that are rolled for every outage. The personnel hatch located at 25 degree azimuth had an area on the floor (approximately 18" x 3") with mechanical damage due to wear and possible scaffold pole marks. The personnel hatch door showed areas of mechanical damage to the primer coat. Adhesion pull tests were performed on random areas on elevation 740 ft. These areas had sound inorganic zinc primer still intact.

Unit 2 Drywell Liner Elevation 777 ft

The condition of the coatings on elevation 777 ft of the drywell was similar to elevation 740 ft. There was widespread mechanical damage of the topcoat to the primer. In general, the overall protective coatings on this elevation appeared to be in good condition.

Unit 2 Drywell Liner Elevation 796 ft

The condition of the protective coatings on elevation 796 ft of the drywell was similar to elevation 740 ft. There was widespread mechanical damage of the topcoat to the primer. In general, the overall coatings on this elevation appeared to be in good condition. Penetration M-23 was power tool cleaned and to SSPC SC-3, Carbozinc 11 was applied.

Unit 2 Drywell Liner Elevation 807 ft

Areas of mechanical damage were present. The majority of the mechanically damaged areas were to the primer only. Approximately 10 to 15 showed damage to the substrate. The areas that were to substrate were minor and exhibited no corrosion. Areas of blistering had occurred where old repairs were performed. These blisters were intact and ranged in size from #6 to #8 medium dense to dense, per ASTM D714. Overall, coatings on elevation 807 ft were generally in good condition. The prioritization of repairs is done for each outage to gain the most efficient time in the drywell and to minimize dose.

Unit 2 Suppression Pool

Inspection of the Unit 2 suppression pool was limited due to access. There was no catwalk in the suppression pool; therefore, inspection was limited to areas observed from the 3 ft x 3 ft platform, which is located at 210 degree azimuth. The suppression pool liner is stainless steel. The supports for downcomers, struts and piping appeared to be carbon steel coated with Carbozinc 11, inorganic zinc. Overall, the inorganic zinc appeared to be in good condition with isolated areas of rusting.

Drywell Head

The outer surface of the drywell head exhibited areas of loose and flaking topcoat with the inorganic zinc primer intact. Four lifting lugs were power tool cleaned to SSPC SP-3 and coated with K&L 65487107. The interior of the drywell head was in good condition. Minor areas of mechanical damage were noted. Approximately fifty areas were power tool cleaned to

SP-3 and coated with K&L 65487107. These mechanically damaged areas probably occurred during the removal of the drywell head.

Results of Recent IWE Examinations

Unit 1 L1R16 Refueling Outage (Spring 2016)

During the Unit 1 L1R16 IWE examination, the following conditions were noted:

Drywell Liner

Paint is missing from the attachment point to the Drywell Liner of two piping supports and three conduit supports. The piping supports are located at 770 ft elevation 335 and 340 azimuth. The conduit supports are located at 760 ft elevation and 775 ft elevation at 30 and 35 degrees. The subject areas should be repaired during the next refueling outage. No reduction in liner wall thickness has occurred and the areas are in an inert atmosphere during operation. There is no effect on operability.

Equipment Hatch (M-112)

Locations of chipped paint on Equipment Hatch have been previously reported. Significant work in the vicinity of the hatch during L1R16 has added to the damaged coating. While the majority of coating is in the outer layer and the primer remains intact, some areas have exposed bare metal.

Findings were discussed with Structural Engineering and concluded that conditions noted are not recordable indication, as there was no effect on structural integrity. Metal reduction was less than 10 percent of thickness and the exposed surface is in an inert operating environment. Coatings are scheduled to be replaced during L1R17.

Suppression Pool Hatch (M-113)

Dings found on hatch bolting threads outside of thread engagement areas. Previously reported and evaluated tool marks noted on hatch flange. Tool marks less than 10 percent of thickness, no impact to structural integrity noted.

Suppression Pool Hatch (M-114)

Dings found on hatch bolting threads outside of thread engagement areas. Previously reported tool marks were noted on hatch flange.

Unit 2 L2R15 Refueling Outage (Spring 2015)
During the Unit 1 L2R15 IWE examination, the following conditions were noted:

Drywell Head Surface and Bolting

Bolt keeper number 29 found to be missing. Bolt keeper was subsequently repaired. Missing coating was found on several areas of outer surface of drywell head.

Drywell Liner

Blistering coating found on 807 ft elevation, which was previously dispositioned during coating examination. Coating was found to be flaking and missing on the drywell liner at 740 ft elevation and 260 degrees azimuth. The area of the defective coating is approximately 2 ft long and 6 in wide. The primer under the coating was not affected. Coating was also missing 2 in around the perimeter of a plate (approximately 12 in by 12 in) welded to the drywell liner 2 to 3 ft above the equipment hatch.

Equipment Hatch (M-112)

Sealing surfaces were observed to be in good condition. Outer coating damaged in areas with primer intact. Locations were previously reported during coatings inspection. Minor dings were found in non-engagement areas of equipment hatch bolting. No impact to structural integrity was noted.

Southeast Suppression Chamber Hatch (M-114)

Some dings were noted in non-engagement areas of hatch bolting. Tooling marks were also observed on outer edge of blind flange. No additional actions were required.

E, M, I, IDF and T Penetrations (Interior)

Staining was noted on some floor penetrations from water spills. Outer coatings were observed to be chipped with primer intact. Coating deficiencies were previously reported during coatings inspection.

Results of Recent IWL Examinations

Unit 1

The Unit 1 exterior containment concrete surface inspection was completed satisfactory between November 2013 and September 2014. The following reportable indications were noted:

740 ft Elevation TIP Room

Reportable Indications: Coating had peeled away revealing a 2 ft vertical crack in concrete just below "E" TIP penetration from 1 to 3 ft above floor; horizontal cracking of coating with some peeling runs the length of the entire wall 4 to 5 ft above floor where containment angles inward; similar horizontal cracking of coating noted near ceiling 6" below electrical penetrations where wall angles outward; numerous cracks in concrete, 3-5" in length, 0.025 in in width surrounding electrical penetration E-10, 20 ft above floor; 2 form tie holes, 4" in diameter, 2.5" deep below electrical penetration E-6; grease run down wall appears to be from floor above near electrical penetration E-6 to ceiling.

Comments and Disposition by Responsible Engineer: There is no loss of structural integrity as a result of noted indications. Therefore, they are acceptable.

740 ft Elevation Drywell Personnel Access Hatch Area

Reportable Indications: Cracks in coating on wall east of airlock in area where containment wall angles inward – coating was found to be generally in good condition with some horizontal cracking in coating above and below area where containment angles inward, maximum crack width was 0.015 in; Spalling on east side of containment wall, 5 ft above floor, adjacent to room wall 3/16th-in maximum depth, approximately 5 in in height by 2 in in width – painted and appears to have been there since construction; Stain, possible leaching or leak from above on containment wall surrounding airlock that runs west half circumference; horizontal cracking on containment wall surrounding airlock where containment bends inward, some peeling of coating on west side of airlock.

Comments and Disposition by Responsible Engineer: No loss of structural integrity as a result of noted indications. Therefore, they are acceptable.

Containment Exterior Concrete Surface: Evidence of grease leakage apparent from 15 degrees to 345 degrees from elevation 740 ft down. All indications were previously recorded and acceptable.

Containment Drywell Floor, Reactor Pedestal Wall

Oil was observed covering approximately forty percent of the drywell concrete floor at elevation 736 ft, 7-1/2 in during the performance of the concrete surface inspection. The oil was observed from 240 degrees azimuth, clockwise to 30 degrees azimuth. The extent of the oil coverage varies from a light transparent sheen to a thicker hardened nontransparent layer. The thicker covering also exhibits some blistering. The Level 3 coatings inspector was present during examination and was consulted regarding the blistering. The material, which had blistered, was the top layer of the qualified coating system, whit the other surface and sealer being intact. Several very small areas (less than 6" x 6") outside of that area with oil residue or oil coverage have chipped top layer coverage most likely as a result of scaffold or other outage maintenance materials and equipment storage activities. There was no structural degradation of the concrete floor observed during the examination. No visible areas of bare concrete were observed. No cracks were observed nor was any separation at the liner-concrete interface observed. As such, no impact on structural integrity was identified. No possible leakage path from the floor surface was observed during this examination.

Disposition by Design Engineering:

1. The observed damage is limited to the upper layer of a three layer drywell floor epoxy coating and no the concrete structure underneath. The coating is not an integral part of the concrete surface but rather protects against water intrusion as well as facilitates its decontamination and or cleaning.

2. Although there were localized areas in which the top epoxy layer was found bubbling, there were negligible amounts of actual loose coating debris, which could affect ECCS strainers or other equipment during a postulated accident event.

3. There was no observed structural degradation of the drywell concrete floor during this inspection.

4. It should be noted that oil has no known detrimental effect on concrete other than staining and in some cases is actually applied to concrete by design, for protection.

Based on the above noted clarifications, the drywell floor integrity has not been affected and will continue to perform its design function.

Unit 2

The Unit 2 exterior containment concrete surface inspection was completed satisfactory between December 2014 and April 2015. The following indications were noted and dispositioned.

Drywell Floor

While conducting the ASME ISI IWE Concrete Inspection of the Drywell Floor, numerous small areas of damaged coating were observed near (within 6 in) but not up to the liner wall/floor interface centered at approximately 310 degrees azimuth. The areas of damaged coating are contained within an arc (bounded by the drywell liner outer wall) approximately 10 ft long and 4 ft wide. The damage consists of cracks in the coating surface with some of the coating having broken away from the surface and presently loose material. No damage was observed to the concrete subsurface. No cracks other than the top surface of coating were observed.

2ECCS820 East/West Concrete Surfaces; 2ECCS786 0-180N, 180-360S Concrete Surfaces

Peeling paint, less than 0.10" crack and water residue from Fuel Pool Water leakage were found on the 2ECCS820 East and West Concrete Surfaces, as well as 2ECCS786 180-360S Concrete Surface, 2ECCS786 0-180N Concrete Surface. No impact to structural integrity or operability as determined by Responsible Engineer.

Personnel Airlock Concrete Walls

Scratched coating was discovered on the personnel airlock concrete walls in several locations. No structural degradation was observed.

Reactor Water Clean Up Heat Exchanger Rooms "A" and "B"

Water residue was discovered on wall in Reactor Water Clean Up Heat Exchanger Rooms "A" and "B" from above elevation.

Outboard Main Steam Isolation Valve (OBMSIV) Room

Small coating peeling was found in OBMSIV Room. No loss of structural integrity or concrete degradation was observed.

Various reportable indications discovered during the examination were previously reported during 2001, 2005 and 2010 inspection and found to be acceptable. No further degradation was observed.

Physical / Visual ISI of Unit 1 and Unit 2 Post-Tensioning Tendons

The physical and visual in-service inspection of the Unit 1 and Unit 2 containment structure post-tensioning systems was performed between August 2013 and August 2014, corresponding to the 35th year (9th period) for Unit 1 and the 30th year (8th period) for Unit 2 since the Structural Integrity Test.

The report concluded the following:

"The post-tensioning system for the LSCS Nuclear Power Plants Units 1 and 2 continues to meet the design requirements. No abnormal degradation of the tendons or containment concrete was observed or recorded during the surveillance. The prestress loss trends indicate that the containment structures will continue to meet the design requirements well beyond the projected 60-year life of the units."

All Unit 1 inspections met applicable acceptance criteria with the following exceptions:

- After removal of the cap, observable moisture was found on the field end of the following tendons, and a Water Notification Letter was issued:
    - V3A (5 oz.)
    - This condition was documented in the Corrective Action Program, which noted that the observable moisture was typical of condensation. The anchorage components were adequately covered and not directly exposed to water. The lack of corrosion or grease contamination and acceptable lift-off testing further confirmed this conclusion and Design Engineering concluded that the negligible volume of condensation water observed was acceptable and does not affect the ability of the tendon to perform its safety function. A work order has been generated to remove the grease cap plug and inspect this tendon for water in the Unit 1 40th year surveillance.
    - V7A (< 1 oz.)
    - This condition was documented in the Corrective Action Program, which noted that the observable moisture was typical of condensation. The anchorage components were adequately covered and not directly exposed to water. The lack of corrosion or grease contamination further confirmed this conclusion and Design Engineering concluded that the negligible volume of condensation water observed was acceptable and does not affect the ability of the tendon to perform its safety function. A work order has been generated to remove the grease cap plug and inspect this tendon for water during the Unit 1 40th year surveillance.
    - V15A (1 oz.)
    - This condition was documented in the Corrective Action Program, which noted that the observable moisture was typical of condensation. The anchorage components were adequately covered and not directly exposed to water. The lack of corrosion or grease contamination further confirmed this conclusion and Design Engineering concluded that the negligible volume of condensation water observed was acceptable and does not affect the ability of the tendon to perform its safety function. A work order has been generated to remove the grease cap plug and inspect this tendon for water in the Unit 1 40th year surveillance.

- The first test of the middle segment of tendon H51BA wire resulted in an elongation percentage of 3.9%, slightly smaller than the required minimum of 4.0% elongation at sample failure. This result was documented in the Corrective Action Program. Subsequent test of the middle segment of the same wire produced an adequate elongation percentage of 4.3%. Design Engineering reviewed the condition and found it to be acceptable. This conclusion is based in part by the negligible quantative deviation value (i.e., a tenth of a percent) but more specifically, because a subsequent piece of wire directly adjoined to the initial sample in question was tested and found acceptable. Moreover, both ends of the same wire were tested and found to be within acceptable elongation limits as well. Based on the aforementioned it was concluded that H51BA tendon is acceptable and does not affect the ability of the tendon to perform its safety function.

All Unit 2 inspections met applicable acceptance criteria with the following exceptions:

- After removal of the cap, observable moisture was found on the field end of the following tendon, and a Water Notification Letter was issued:
    - V203B (0.5 oz.)
    - This condition was documented in the Corrective Action Program, which noted that the observable moisture was typical of condensation. The anchorage components were adequately covered and not directly exposed to water. The lack of corrosion or grease contamination further confirmed this conclusion and Design Engineering concluded that the negligible volume of condensation water observed was acceptable and does not affect the ability of the tendon to perform its safety function. A work order has been generated to remove the grease cap plug and inspect this tendon for water during the Unit 2 35th year surveillance.

- After removal of grease caps, the field end of vertical tendon V212C was found with one protruding wire that was not previously reported. The wire protruded 0.65 in. This finding was documented in the plant's Corrective Action Program. Design Engineering concluded that the condition was acceptable based on the following: Design Analysis 49D Revision 6, "Assessment of Containment Drywell Floor, Base Mat & Pedestal in As-Built Condition" qualifies tendons assuming three wires are missing from the initial design ninety wire tendon. Assuming the protruding wire is due to the wire being broken (as opposed to bound), the resulting number of effective wires is 89, which is greater than the 87 required per the noted design analysis.

- After removal of grease caps, the field end of vertical tendon V204C was found with one missing buttonhead that was not previously reported. Additionally, the shop end of vertical tendon V204C was found with one missing buttonhead that was not previously reported. These findings were documented in the plant's Corrective Action Program. Design Engineering concluded that the condition was acceptable based on the following: Design Analysis 49D Revision 6, "Assessment of Containment Drywell Floor, Base Mat & Pedestal in As-Built Condition" qualifies tendons assuming three wires are missing from the initial design ninety wire tendon. Assuming that the missing buttoncaps on both the field end and shop end are not the same wire, the resulting number of effective wires is 88, which is greater than the 87 required per the noted design analysis.

The results found during the tendon surveillances were reviewed by the Responsible Engineer. Various non-conformances were observed, documented, evaluated and determined to be acceptable. No loss of structural integrity was identified, and the post-tensioning system for LSCS Units 1 and 2 continues to meet design requirements.

3.6 License Renewal Aging Management

By letter dated December 9, 2014, EGC, submitted the License Renewal Application (LRA) in accordance with Title 10 of the Code of Federal Regulations 10 CFR Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants" (Reference 30). By letter dated October 19, 2016, the NRC issued renewed facility operating licenses for LSCS, Units 1 and 2 (Reference 32).

The renewed LSCS, Units 1 and 2, operating licenses will expire as follows:

- Renewed facility operating license No. NPF-11 for Unit 1 expires at midnight on April 17, 2042.
- Renewed facility operating license No. NPF-18 for Unit 2 expires at midnight on December 16, 2043.

The following programs, which are part of the supporting basis for this submittal, are also Aging Management Programs for LSCS.

ASME Section XI, Subsection IWE

The ASME Section XI, Subsection IWE aging management program is an existing condition monitoring program based on ASME Code and complies with the provisions of 10 CFR 50.55a. The program consists of periodic visual and volumetric examination of pressure-retaining components of steel and concrete containments for signs of degradation, and assessment of damage. The program includes aging management of surfaces and components such as the steel and stainless steel containment liner plate surfaces and components, including its integral attachments, drywell floor liner, downcomers and bracing, penetration sleeves and closures, vacuum breaker piping and valves, pressure retaining bolting for containment closure, personnel airlock and equipment hatches, drywell head, and other pressure-retaining components for loss of material, loss of preload, loss of leak tightness, and fretting or lockup in air-indoor uncontrolled and treated water environments.

The current program complies with ASME Section XI, Subsection IWE, 2001 Edition through the 2003 Addenda, supplemented with the applicable requirements of 10 CFR 50.55a. In accordance with 10 CFR 50.55a(g)(4), the ISI program is updated each successive 120-month inspection interval to comply with the requirements of the latest edition of the ASME Code specified 12 months before the start of the inspection interval. The ASME Code edition consistent with the provisions of 10 CFR 50.55a will be used during the period of extended operation.

LSCS primary containments are BWR Mark II concrete containments. High strength containment bolting susceptible to cracking is not used; therefore, surface examination to detect cracking is not applicable. Environments include air-indoor uncontrolled and treated

water. The scope of the ASME Section XI, Subsection IWE program is consistent with the scope identified in Subsection IWE-1000 and includes the Class MC pressure-retaining components and their integral attachments including wetted surfaces of submerged areas of the pressure suppression chamber and vent system, containment pressure-retaining bolting, and metal containment surface areas, including welds and base metals. Containment seals and gaskets are including in the scope of the 10 CFR Part 50, Appendix J program. Service Level 1 coatings are included in the scope of the Protective Coating Monitoring and Maintenance Program.

The program utilizes inspections that detect degradation before loss of intended function. The ASME Code Section XI, Subsection IWE program relies on design change procedures that will be enhanced to include guidance to ensure proper specification of bolting material, lubricant or sealants, and installation torque or tension to prevent or mitigate degradation and failure of structural bolting. The program implements the requirements of IWE by providing visual examination (General Visual and VT-3) and augmented inspections (VT-1) for evidence of aging effects that could affect structural integrity or leak tightness of the primary containment. Areas subject to augmented inspection are subject to visual inspection (VT-1) and volumetric (ultrasonic) examination techniques as required by engineering. The program addresses the E-A and E-C examination categories described in Table IWE-2500-1 and as approved per 10 CFR 50.55a. The program specifies examinations of accessible surfaces to detect aging effects as addressed in IWE-3500. The frequency and scope of examinations specified is in accordance with 10 CFR 50.55a, and ASME Section XI, Subsection IWE-2400.

The ASME Section XI, Subsection IWE program complies with ASME Section, XI Subsection IWE for inspection of Class MC and metallic shell and penetration liners of Class CC pressure-retaining components and their integral attachments, in accordance with the provisions of 10 CFR 50.55a. The monitoring methods have been demonstrated effective in detecting the applicable aging effects and the frequency of monitoring is adequate to prevent significant aging. The concrete portions of the primary containments are inspected in accordance with ASME Section XI, Subsection IWL program. The ASME Section XI, Subsection IWE program provides for periodic inspections for the presence of age-related degradation on all accessible surfaces of the containment on a scheduled basis. When examination results require an evaluation or the component is repaired and is found to be acceptable for continued service, the areas containing such flaws, degradation, or repair are reexamined during the next inspection period, in accordance with Examination Category E-C.

The acceptance criteria for the ASME Section XI, Subsection IWE program are in accordance with the requirements of the ASME Code, Subsections IWE-3000 and IWE-3500.

Category E-A examinations are conducted by a certified VT-3 examiner or engineer, and Category E-C examinations are conducted by a certified VT-1 examiner or engineer. Indications are evaluated and compared to acceptance standards. The IWE Responsible Individual is responsible for evaluation of examination results. Unacceptable conditions are recorded and documented in accordance with the corrective action program and supplemental examinations are performed in accordance with IWE-3200. Conditions that do not meet the acceptance criteria are accepted by an engineering evaluation or corrected by repair or replacement in accordance with IWE-3122.

Repairs and reexaminations, when required, are performed in accordance with IWA-4000 as required by IWE-3124 and the components are repaired or replaced to the extent necessary to

meet the acceptance standards of IWE-3500. Component reexaminations are conducted in accordance with the requirements of IWA-2200 and the results are recorded to demonstrate that the repair meets the owner defined acceptance standards per IWE-3500. The program will be enhanced, as noted below, to provide reasonable assurance that the ASME Section XI, Subsection IWE program aging effects will be adequately managed during the period of extended operation.

The program will be enhanced to provide reasonable assurance that the ASME Section XI, Subsection IWE program aging effects will be adequately managed during the period of extended operation.

NUREG-1801 (Reference 31) Consistency

The ASME Section XI, Subsection IWE aging management program will be consistent with the ten elements of aging management program XI.S1, "ASME Section XI, Subsection IWE," specified in NUREG-1801.

ASME Section XI, Subsection IWL

The ASME Section XI, Subsection IWL aging management program is an existing condition monitoring program which implements examination requirements of the ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWL for Class CC Concrete Components of Light-Water Cooled Plants, as mandated by 10 CFR 50.55a. The scope of the program includes reinforced concrete and the unbonded post-tensioning system and manages the identified aging effects of components within the scope of license renewal in air-indoor uncontrolled, ground water, soil and water-flowing environments.

The current program complies with ASME Section XI, Subsection IWL, 2001 Edition through the 2003 Addenda, supplemented with the applicable requirements of 10 CFR 50.55a. In accordance with 10 CFR 50.55a(g)(4), the ISI program is updated each successive 120-month inspection interval to comply with the requirements of the latest edition of the ASME Code specified 12 months before the start of the inspection interval. The ASME Code edition consistent with the provisions of 10 CFR 50.55a will be used during the period of extended operation.

The primary inspection method is a visual examination, supplemented by testing. Inspection methods, inspected parameters, and acceptance criteria are in accordance with ASME Section XI, Subsection IWL as approved by 10 CFR 50.55a. Accessible concrete surfaces are subject to General Visual examination to detect deterioration and distress such as defined in ACI 201.1R and ACI 349.3R, including loss of material, cracking, increase in porosity and permeability, and loss of bond in the air-indoor uncontrolled environment. Concrete surfaces that exhibit deterioration and distress, based on General Visual examination, as subject to Detailed Visual examination to determine the magnitude and extent of deterioration and distress. In addition, concrete surfaces at the bearing plates for tendon anchorages are subject to a Detailed Visual examination. One tendon wire of each type is also examined for loss of material and subject to physical testing to determine yield strength, ultimate tensile strength, and elongation. Tendon corrosion protection medium is analyzed for alkalinity, water content, and soluble ion concentrations. Any free water contained in the anchorage end cap and free water that drains from tendons during the examination is documented. Samples of the free water are also analyzed for pH.

Prestressing forces are measured in selected sample tendons. Evaluation of prestressing forces is addressed in the Concrete Containment Tendon Prestress program. Acceptance criteria, corrective actions and expansion of the inspection scope when degradation exceeding the acceptance criteria is found, are in accordance with ASME Section XI, Subsection IWL. Prestressing forces of the sample and common tendons are compared to the minimum required values predicted for the specific tendon at the specific time of the test, as described in RG 1.35.1. Conditions that do not meet acceptance criteria are entered into the corrective action program.

The augmented examination requirements following post-tensioning system repair and replacement activities are in accordance with ASME Section XI, Subsection IWL. Post-tensioning system repair and replacement activities following post-tensioning system repair and replacement activities are in accordance with ASME Section XI, Subsection IWL.

NUREG-1801 (Reference 31) Consistency

The ASME Section XI, Subsection IWL aging management program will be consistent with the ten elements of aging management program XI.S2, "ASME Section XI, Subsection IWL," specified in NUREG-1801.

10 CFR Part 50, Appendix J

The 10 CFR Part 50, Appendix J aging management program is an existing condition monitoring program that manages detection of aging effects including loss of material, loss of leak tightness, and loss of bolting preload in the containment and various systems penetrating primary containment. The program also detects loss of sealing due to degradation of gaskets and seals. The program manages steel containment structural elements, concrete embedments, penetration sleeves, hatches, airlocks, and bolting in air-indoor uncontrolled and treated water environments.

The program consists of tests performed in accordance with the regulations and guidance provided in 10 CFR 50, Appendix J, Option B, RG 1.163, NEI 94-01 and ANSI/ANS-56.8.

Containment leak rate tests are performed to assure that leakage through the containment and systems and components penetrating containment does not exceed allowable leakage limits specified in the TS. An ILRT is performed during a period of reactor shutdown at the frequency specified in 10 CFR Part 50, Appendix J, Option B. LLRTs are performed on isolation valves and containment access penetrations at frequencies that comply with the requirements of 10 CFR 50, Appendix J, Option B.

NUREG-1801 (Reference 31) Consistency

The 10 CFR Part 50, Appendix J aging management program is consistent with the ten elements of aging management program XI.S4, "10 CFR Part 50, Appendix J," specified in NUREG-1801.

Protective Coating Monitoring and Maintenance Program

The Protective Coating and Maintenance Program is an existing mitigative and condition monitoring program which manages the effects of loss of coating integrity of Service Level I coatings inside the primary containment (as defined by RG 1.54, Revision 2) in air-indoor and treated water environments. The failure of the Service Level I coatings could adversely affect the operation of the emergency core cooling systems (ECCS) by clogging the ECCS suction strainers. Proper maintenance of the Service Level I coating ensures that coating degradation will not impact the operability of the ECCS systems. The Protective Coating and Maintenance Program includes coating system selection, application, inspection, assessment, maintenance and repair for any condition that adversely affects the ability of Service Level I coatings to function as intended.

Service Level I coatings will prevent or minimize the loss of material due to corrosion but these coatings are not credited for managing the effects of corrosion for the carbon steel containment liners and components. This program ensures only that the Service Level I coatings maintain adhesion to not affect the intended function of the ECCS suction strainers.

This program also provides controls over the amount of unqualified coating, which is defined as coating inside the primary containment that has not passed the required laboratory testing, including irradiation and simulated Design Basis Accident (DBA) conditions. Unqualified coating may fail in a way to affect the intended function of the ECCS suction strainers. Therefore, the quantity of unqualified coating is controlled to ensure that the amount of unqualified coating in the primary containment is kept within acceptable design limits.

NUREG-1801 (Reference 31) Consistency

The Protective Coating Monitoring and Maintenance aging management program is consistent with the ten elements of aging management program XI.S8, "Protective Coating Monitoring and Maintenance Program," specified in NUREG-1801.

3.7 NRC SE Limitations and Conditions

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

The NRC found that the use of NEI TR 94-01, Revision 2, was acceptable for referencing by licensees proposing to amend their TSs to permanently extend the ILRT surveillance interval to 15 years, provided the following conditions as listed in Table 3.7.1-1 were satisfied:

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

Limitation/Condition (From Section 4.0 of SE)	LSCS 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.)	LSCS will utilize the definition in NEI 94-01 Revision 3-A, Section 5.0. This definition has remained unchanged from Revision 2-A to Revision 3-A of NEI 94-01.

Table 3.7.1-1 – NEI 94-01 Revision 2-A Limitations and Conditions	
Limitation/Condition (From Section 4.0 of SE)	**LSCS Response**
The licensee submits a schedule of containment inspections to be performed prior to and between Type A tests. (Refer to SE Section 3.1.1.3.)	Reference Sections 3.4.3 and 3.4.4
The licensee addresses the areas of the containment structure potentially subjected to degradation. (Refer to SE Section 3.1.3.)	Reference Section 3.4.3 and Section 3.5 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 that would require the performance of a Type A ILRT or a Structural Integrity Test (SIT).
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 that it is an unforeseen emergent condition. (Refer to SE Section 3.1.1.2.)	LSCS will follow the requirements of NEI 94-01 Revision 3-A, Section 9.1. This requirement has remained unchanged from Revision 2-A to Revision 3-A of NEI 94-01. In accordance with the requirements of 94-01 Revision 2-A, SE Section 3.1.1.2, LSCS will also demonstrate to the NRC that an unforeseen emergent condition exists in the event an extension beyond the 15-year interval is required.
For plants licensed under 10 CFR Part 52, applications requesting a permanent extension of the ILRT surveillance interval to 15 years should be deferred until after the construction and testing of containments for that design have been completed and applicants have confirmed the applicability of NEI 94-01, Revision 2, and EPRI Report No. 1009325, Revision 2, including the use of past containment ILRT data.	Not applicable. LSCS was not licensed under 10 CFR Part 52.

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

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

Topical Report Condition 1

NEI TR 94-01, Revision 3, is requesting that the allowable extended interval for Type C LLRTs be increased to 75 months, with a permissible extension (for non-routine emergent conditions) of nine months (84 months total). The staff is allowing the extended interval for Type C LLRTs be increased to 75 months with the requirement that a licensee's post-outage report include the margin between the Type B and Type C leakage rate summation and its regulatory limit. In addition, a corrective action plan shall be developed to restore the margin to an acceptable level. The staff is also allowing the non-routine emergent extension out to 84-months as

applied to Type C valves at a site, with some exceptions that must be detailed in NEI TR 94-01, Revision 3. At no time shall an extension be allowed for Type C valves that are restricted categorically (e.g., BWR MSIVs), and those valves with a history of leakage, or any valves held to either a less than maximum interval or to the base refueling cycle interval. Only non-routine emergent conditions allow an extension to 84 months.

Response to Condition 1

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

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

Response to Condition 1, Issue 1

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

Response to Condition 1, Issue 2

When the potential leakage understatement adjusted Type B and C MNPLR total is greater than the LSCS 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 LSCS leakage limit. The corrective action plan shall focus on those components which have contributed the most to the increase in the leakage summation value and what manner of timely corrective action, as deemed appropriate, best focuses on the prevention of future component leakage performance issues to maintain an acceptable level of margin.

Response to Condition 1, Issue 3

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

Topical Report Condition 2

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

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

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

Response to Condition 2

Condition 2 presents two (2) separate issues that are required to be addressed. They are 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, LSCS will conservatively apply a potential leakage

understatement adjustment factor of 1.25 to the As-Left leakage total for each Type C component currently on the 75-month extended test interval. This will result in a combined conservative Type C total for all 75-month LLRTs being "carried forward" and will be included whenever the total leakage summation is required to be updated (either while on line or following an outage). When the potential leakage understatement adjusted leak rate total for those Type C components being tested on a 75-month extended interval is summed with the non-adjusted total of those Type C components being tested at less than the 75-month interval and the total of the Type B tested components, if the MNPLR is greater than the LSCS 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 LSCS leakage limit. The corrective action plan shall focus on those components which have contributed the most to the increase in the leakage summation value and what manner of timely corrective action, as deemed appropriate, best focuses on the prevention of future component leakage performance issues.

Response to Condition 2, Issue 2

If the potential leakage understatement adjusted leak rate MNPLR is less than the LSCS leakage summation limit of 0.50 L_a, then the acceptability of 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, Parts 1, 2 that 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 LSCS, in the event an adverse trend in the aforementioned potential leakage understatement adjusted Type B and C summation is identified, then an analysis and determination of a corrective action plan shall be prepared to restore the trend and associated margin to an acceptable level. The corrective action plan shall focus on those components which have contributed the most to the adverse trend in the leakage summation value and what manner of timely corrective action, as deemed appropriate, best focuses on the prevention of future component leakage performance issues.

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

3.8 Conclusion

NEI 94-01, Revision 3-A, dated July 2012, and the conditions and limitations specified in NEI 94-01, Revision 2-A, dated October 2008, describes an NRC-accepted approach for implementing the performance-based requirements of 10 CFR Part 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. LSCS 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 LSCS 10 CFR Part 50, Appendix J testing program plan.

Based on the previous ILRT tests conducted at LSCS, 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 Part 50, Appendix J and the overlapping inspection activities performed as part of the following LSCS inspection programs:

- Containment Inservice Inspection Program (IWE / IWL)
- Primary Containment Inspection Program per TS SR 3.6.1.1.1
- Containment Post Tensioning Tendon Examinations per TS SR 3.6.1.1.2
- Inspection of Service Level 1 Coatings

This experience is supplemented by risk analysis studies, including the LSCS risk analysis provided in Attachment 3. The findings of the risk assessment confirm the general findings of previous studies, on a plant-specific basis, that extending the ILRT interval from ten to 15 years results in a very small change to the LSCS risk profiles.

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 Part 50, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors." Appendix J specifies containment leakage testing requirements, including the types required to ensure the leak-tight integrity of the primary reactor containment and systems and components that 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 Part 50, Appendix J, the test frequency is based upon an evaluation that reviewed "as-found" leakage history to determine the frequency for leakage testing which provides assurance that leakage limits will be maintained. The change to the Type A test frequency did not directly result in an increase in containment leakage. Similarly, the proposed change to the Type C test frequency will not directly result in an increase in containment leakage.

EPRI TR-1009325, Revision 2, provided a risk impact assessment for optimized ILRT intervals up to 15 years, utilizing current industry performance data and risk informed guidance. NEI 94-01, Revision 3-A, Section 9.2.3.1 states that Type A ILRT intervals of up to 15 years are allowed by this guideline. The Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals, EPRI Report 1018243 (Formerly TR-1009325, Revision 2) indicates that, in general, the risk impact associated with ILRT interval extensions for intervals up to 15 years is small. However, plant-specific confirmatory analyses are required.

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

For EPRI Report No. 1009325, Revision 2, a risk-informed methodology using plant-specific risk insights and industry ILRT performance data to revise ILRT surveillance frequencies, the NRC finds that the proposed methodology satisfies the key principles of risk-informed decision making applied to changes to TSs as delineated in RG 1.177 and RG 1.174. The NRC, therefore, found that this guidance was acceptable for referencing by licensees proposing to amend their TS in regards to containment leakage rate testing, subject to the limitations and conditions noted in Section 4.0 of the SE.

The NRC 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 Part 50, Appendix J, as modified by the conditions and limitations summarized in Section 4.0 of the associated Safety Evaluation. This guidance included provisions for extending Type C LLRT intervals up to 75 months. Type C testing ensures that individual containment isolation valves 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, 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 SE 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 Part 50, Appendix J.

4.2 Precedent

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

- Surry Power Station, Units 1 and 2 (Reference 24)
- Donald C. Cook Nuclear Plant, Units 1 and 2 (Reference 25)
- Beaver Valley Power Station, Unit Nos. 1 and 2 (Reference 26)
- Calvert Cliffs Nuclear Power Plant, Unit Nos. 1 and 2 (Reference 27)
- Peach Bottom Atomic Power Station, Units 2 and 3 (Reference 28)
- Comanche Peak Nuclear Power Plant, Units 1 and 2 (Reference 29)

4.3 No Significant Hazards Consideration

In accordance with 10 CFR 50.90, "Application for amendment of license, construction permit or early site permit," Exelon Generation Corporation, LLC (EGC) requests an amendment to Facility Operating License Nos. NPF-11 and NPF-18 for LaSalle County Station (LSCS), Unit 1 and Unit 2. The proposed change revises TS 5.5.13, "Primary Containment Leakage Rate Testing Program," to allow for the permanent extension of the Type A Integrated Leak Rate Testing (ILRT) and Type C Leak Rate Testing frequencies.

Specifically, the proposed change will revise LSCS TS 5.5.13, by replacing the references to Regulatory Guide (RG) 1.163, "Performance-Based Containment Leak-Test Program," with a reference to NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J," Revision 3-A, and the conditions and limitations specified in NEI 94-01, Revision 2-A, as the documents used by LSCS to implement the performance-based leakage testing program in accordance with Option B of 10 CFR 50, Appendix J. The proposed amendment is risk-informed and follows the guidance in RG 1.174, "An Approach For Using Probabilistic Risk Assessment In Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," Revision 2.

The License Amendment Request (LAR) also proposes administrative changes to TS 5.5.13 to delete the information regarding the performance of the next LSCS Type A tests to be performed no later than June 13, 2009, for Unit 1 and no later than prior to startup following the L2R12 refueling outage for Unit 2 as these Type A tests have already occurred.

Additionally, the LAR proposes an administrative change to the LSCS Unit 1 Facility Operating License to delete Condition 2.D.(e) of the LSCS Unit 1 Operating License regarding conducting the third Type A Test of each ten year service period when the plant is shutdown for the 10 year plant inservice inspection. Similarly, this LAR proposes an administrative change to the LSCS Unit 2 Facility Operating License to delete Condition 2.D.(c) of the LSCS Unit 2 Operating License regarding conducting the third Type A test of each ten year service period when the plant is shutdown for the 10 year plant inservice inspection. The Unit 1 and Unit 2 Operating License Conditions will be deleted since the Type A test frequency will be 15 years following approval of this LAR.

EGC 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 amendment to the TS involves the extension of the LSCS Type A containment test interval to 15 years and the extension of the Type C test interval to 75 months. The current Type A test interval of 120 months (10 years) would be extended on a permanent basis to no longer than 15 years from the last Type A test. The current Type C test interval of 60 months for selected components would be extended on a performance basis to no longer than 75 months. Extensions of up to nine months (total maximum interval of 84 months for Type C tests) are permissible only for non-routine emergent conditions.

   The proposed extension does not involve either a physical change to the plant or a change in the manner in which the plant is operated or controlled. The containment is designed to provide an essentially leak tight barrier against the uncontrolled release of radioactivity to the environment for postulated accidents. As such, the containment and the testing requirements invoked to periodically demonstrate the integrity of the containment exist to ensure the plant's ability to mitigate the consequences of an accident, and do not involve the prevention or identification of any precursors of an accident. The change in dose risk for changing the Type A test frequency from three-per-ten years to once-per-fifteen years, measured as an increase to the total integrated dose risk for all internal events accident sequences for LSCS, is 1.23E-02 person-rem/yr (0.33%) using the EPRI guidance with the base case corrosion included. The change in dose risk drops to 3.15E-03 person-rem/yr (0.08%) when using the EPRI Expert Elicitation methodology. The values calculated per the EPRI guidance are all lower than the acceptance criteria of ≤ 1.0 person-rem/yr or < 1.0% person-rem/yr defined in Section 1.3 of Attachment 3 of this submittal. The results of the risk assessment for this amendment meet these criteria. Moreover, the risk impact for the ILRT extension when compared to other severe accident risks is negligible. Therefore, this proposed extension does not involve a significant increase in the probability of an accident previously evaluated.

   As documented in NUREG-1493, Type 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 LSCS Type A test history supports this conclusion.

   The integrity of the containment is subject to two types of failure mechanisms that can be categorized as: (1) activity based and (2) time based. Activity based failure mechanisms are defined as degradation due to system and/or component modifications or maintenance. Local leak rate test requirements and administrative controls such as configuration management and procedural requirements for system restoration ensure that containment integrity is not degraded by plant modifications or maintenance activities. The design and construction requirements of the containment combined with the containment inspections performed in accordance with ASME Section XI and TS requirements serve to

provide a high degree of assurance that the containment would not degrade in a manner that is detectable only by a Type A test. Based on the above, the proposed extensions do not significantly increase the consequences of an accident previously evaluated.

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

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

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

   Response: No.

   The proposed amendment to the TS involves the extension of the LSCS Type A containment test interval to 15 years and the extension of the Type C test interval to 75 months. The containment and the testing requirements to periodically demonstrate the integrity of the containment exist to ensure the plant's ability to mitigate the consequences of an accident do not involve any accident precursors or initiators. The proposed change does not involve a physical change to the plant (i.e., no new or different type of equipment will be installed) or a change to the manner in which the plant is operated or controlled.

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

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

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

   Response: No.

   The proposed amendment to TS 5.5.13 involves the extension of the LSCS Type A containment test interval to 15 years and the extension of the Type C test interval to 75 months for selected components. This amendment does not alter the manner in which safety limits, limiting safety system set points, or limiting conditions for operation are determined. The specific requirements and conditions of the TS Containment Leak Rate Testing Program exist to ensure that the degree of containment structural integrity and leak-tightness that is considered in the plant safety analysis is maintained. The overall containment leak rate limit specified by TS is maintained.

The proposed change involves only the extension of the interval between Type A containment leak rate tests and Type C tests for LSCS. The proposed surveillance interval extension is bounded by the 15-year ILRT Interval and the 75-month Type C test interval currently authorized within NEI 94-01, Revision 3-A. Industry experience supports the conclusion that Type B and C testing detects a large percentage of containment leakage paths and that the percentage of containment leakage paths that are detected only by Type A testing is small. The containment inspections performed in accordance with ASME Section XI and TS serve to provide a high degree of assurance that the containment would not degrade in a manner that is detectable only by Type A testing. The combination of these factors ensures that the margin of safety in the plant safety analysis is maintained. The design, operation, testing methods and acceptance criteria for Type A, B, and C containment leakage tests specified in applicable codes and standards would continue to be met, with the acceptance of this proposed change, since these are not affected by changes to the Type A and Type C test intervals.

The proposed amendment also deletes exceptions previously granted to allow one time extensions of the ILRT test frequency for LSCS. These exceptions were for activities that would have already taken place by the time this amendment is approved; therefore, their deletion is solely an administrative action and does not change how the unit is operated and maintained. Thus, there is no reduction in any margin of safety.

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

Based on the above, EGC 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. NEI 94-01, Revision 3-A, "Nuclear Energy Institute Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J," ADAMS Accession No. ML12221A202, dated July 2012

2. NEI 94-01, Revision 2-A, "Nuclear Energy Institute Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J," ADAMS Accession No. ML100620847, dated October 2008

3. ANSI/ANS-56.8-2002, "Containment System Leakage Testing Requirements," dated November 27, 2002

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

5. 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," dated May 2011

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

7. NEI 94-01, Revision 0, "Nuclear Energy Institute Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J," dated July 21, 1995

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

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

10. Letter from M. J. Maxin (U.S. Nuclear Regulatory Commission) 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 Part 50, Appendix J' and Electric Power Research Institute (EPRI) Report No. 1009325, Revision 2, August 2007, 'Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals' (TAC No. MC9663)," ADAMS Accession No. ML081140105, dated June 25, 2008

11. Letter from S. Bahadur (U.S. Nuclear Regulatory Commission) to B. Bradley (NEI), "Final Safety Evaluation of Nuclear Energy Institute (NEI) Report, 94-01, Revision 3, 'Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J' (TAC No. ME2164)," ADAMS Accession No. 121030286, dated June 8, 2012

12. Letter from M. D. Lynch (U.S. Nuclear Regulatory Commission) to D. L. Farrar (Commonwealth Edison Company), "Issuance of Amendments Related to the Implementation of 10 CFR Part 50, Appendix J, Option B (TAC Nos. M94063 and M94064)," ADAMS Accession No. ML021130158, dated March 11, 1996

13. Letter from W. A. Macon, Jr. (U.S. Nuclear Regulatory Commission) to O. D. Kingsley (Exelon Generation Company, LLC), "LaSalle County Station, Units 1 and 2 – Issuance of Amendments (TAC Nos. MB2187 and MB2188)," ADAMS Accession No. ML012850399, dated November 7, 2001

14. Letter from W. A. Macon, Jr. (U.S. Nuclear Regulatory Commission) to J. L. Skolds (Exelon Generation Company, LLC), "LaSalle County Station, Units 1 and 2, Issuance of Amendments Re: Integrated Leakage Rate Test Interval (TAC Nos. MB6574 and MB6575)," ADAMS Accession No. ML033010008), dated November 19, 2003

15. Letter from D. V. Pickett (U.S. Nuclear Regulatory Commission) to C. M. Crane (Exelon Generation Company, LLC), "LSCS County Station, Units 1 and 2, Issuance of Amendments (TAC Nos. MC0496 and MC0497)," ADAMS Accession No. ML042570011), dated October 14, 2004

16. Letter from S. P. Sands (U.S. Nuclear Regulatory Commission) to C. M. Crane (Exelon Generation Company, LLC), "LaSalle County Station, Unit 2, Issuance of Amendment Re: Primary Containment Leakage Testing Program (TAC No. MD1298)," ADAMS Accession No. ML062770136), dated January 24, 2007

17. Letter from C. Gratton (U.S. Nuclear Regulatory Commission) to M. J. Pacilio (Exelon Nuclear), "LaSalle County Station, Units 1 and 2 – Issuance of Amendments Re: Application of Alternative Source Term (TAC Nos. ME0068 and ME0069)," ADAMS Accession No. ML101750625), dated September 6, 2010.

18. Letter from B. Purnell (U.S. Nuclear Regulatory Commission) to B. C. Hanson (Exelon Generation Company, LLC), "LaSalle County Station, Units 1 and 2, Issuance of Amendments Revising Peak Calculated Primary Containment Internal Pressure (TAC Nos. MF2690 and MF2691)," ADAMS Accession No. ML14353A083, dated January 29, 2015

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

20. Letter from C. H. Cruse (Constellation Nuclear, Calvert Cliffs Nuclear Power Plant) to U.S. Nuclear Regulatory Commission, "Response to Request for Additional Information Concerning the License Amendment Request for a One-Time Integrated Leakage Rate Test Extension," ADAMS Accession No. ML020920100, dated March 27, 2002

21. NEI 05-04, "Process for Performing Follow-on PRA Peer Reviews Using the ASME PRA Standard," Nuclear Energy Institute, Revision 1, Draft G, dated November 2007

22. ASME/American Nuclear Society, "Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications," ASME/ANS RA-Sa-2009, March 2009

23. Regulatory Guide 1.200, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," Revision 1, dated January 2007

24. Letter from S. Williams (U.S. Nuclear Regulatory Commission) to D. A. Heacock (Virginia Electric and Power Company), "Surry Power Station, Units 1 and 2 - Issuance of Amendment Regarding the Containment Type A and Type C Leak Rate Tests (TAC Nos. MF2612 and MF2613)," dated July 3, 2014 (ADAMS Accession No. ML14148A235)

25. Letter from A. W. Dietrich (U.S. Nuclear Regulatory Commission) to L. J. Weber (Indiana Michigan Power Company), "Donald C. Cook Nuclear Plant, Units 1 and 2 - Issuance of Amendments Re: Containment Leakage Rate Testing Program (TAC Nos. MF3568 and MF3569)," dated March 30, 2015 (ADAMS Accession No. ML15072A264)

26. Letter to from T. A. Lamb (U.S. Nuclear Regulatory Commission) to E. A. Larson (FirstEnergy Nuclear Operating Company), "Beaver Valley Power Station, Unit Nos. 1 and 2 - Issuance of Amendment Re: License Amendment Request to Extend Containment Leakage Rate Test Frequency (TAC Nos. MF3985 and MF3986)," dated April 8, 2015 (ADAMS Accession No. ML15078A058)

27. Letter from A. N. Chereskin (U.S. Nuclear Regulatory Commission) to G. H. Gellrich (Exelon Generation Company, LLC), "Calvert Cliffs Nuclear Power Plant, Unit Nos. 1 and 2 - Issuance of Amendments Re: Extension of Containment Leakage Rate Testing Frequency (TAC Nos. MF4898 and MF4899), dated July 16, 2015 (ADAMS Accession No. ML15154A661)

28. Letter from R. B. Ennis (U.S. Nuclear Regulatory Commission) to B. C. Hanson (Exelon Nuclear), "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 (ADAMS Accession No. ML15196A559)

29. Letter from B. K. Singal (U.S. Nuclear Regulatory Commission) to R. Flores (Luminant Generation Company LLC), "Comanche Peak Nuclear Power Plant, Units 1 and 2 – Issuance of Amendments Re: Technical Specification Change for Extension of the Integrated Leak Rate Test Frequency from 10 to 15 Years (CAC Nos. MF5621 and MF5622)," dated December 30, 2015 (ADAMS Accession No. ML15309A073)

30. Letter from M. P. Gallagher (Exelon Generation Company, LLC) to U. S. Nuclear Regulatory Commission, "Application for Renewed Operating License," dated December 9, 2014 (ADAMS Accession No. ML14343A840)

31. NUREG-1801, Revision 2, "Generic Aging Lessons Learned (GALL) Report, Final Report," ADAMS Accession No. ML103490041, dated December 2010

32. Letter from M. J. Maxin (U.S. Nuclear Regulatory Commission) to J. C. Butler (Nuclear Energy Institute), "Final Safety Evaluation for Nuclear Energy Institute (NEI) Topical Report (TR) 94-01, Revision 2, 'Industry Guideline for Implementing Performance-Based Option Of 10 CFR Part 50, Appendix J' and Electric Power Research Institute (EPRI) Report No. 1009325, Revision 2, August 2007, 'Risk Impact Assessment Of Extended Integrated Leak Rate Testing Intervals' (TAC No. MC9663)," ADAMS Accession No. ML081140105, dated June 25, 2008

33. Letter from J. S. Mitchell (U.S. Nuclear Regulatory Commission) to M.P. Gallagher (Exelon Generation Company, LLC), "Issuance of Renewed Facility Operating Licenses for LaSalle County Station, Units 1 and 2 (TAC Nos. MF5347 and MF5346)," dated October 19, 2016

ATTACHMENT 2

Markup of Renewed Facility Operating Licenses and
Technical Specifications Pages

LASALLE COUNTY STATION
UNITS 1 AND 2

Docket Nos. 50-373 and 50-374

Renewed Facility Operating License Nos. NPF-11 and NPF-18

Unit 1 Operating License Page 10
Unit 2 Operating License Page 10
TS Page 5.5-12
TS Page 5.5-13
INSERT

Am. 102 03/16/95

D. The facility requires exemptions from certain requirements of 10 CFR Part 50, 10 CFR Part 70, and 10 CFR Part 73. These include:

(a) Exemptions from certain requirements of Appendices G, H and J and 10 CFR Part 73 are described in the Safety Evaluation Report and Supplement No. 1, No. 2, No. 3 to the Safety Evaluation Report.

(b) DELETED

(c) DELETED

(d) DELETED

DELETED

(e) ~~An exemption from the requirement of paragraph III.D of Appendix J to conduct the third Type A test of each ten-year service period when the plant is shutdown for the 10-year plant inservice inspections. Exemption (e) is described in the safety evaluation accompanying amendment No. 102 to this License.~~

Am. 112 04/05/96

(f) An exemption was granted to remove the Main Steam Isolation Valves (MSIVs) from the acceptance criteria for the combined local leak rate test (Type B and C), as defined in the regulations of 10 CFR Part 50, Appendix J, Option B, Paragraph III.B. Exemption (f) is described in the safety evaluation accompanying Amendment No. 112 to this License.

These exemptions are authorized by law and will not endanger life or property or the common defense and security and are otherwise in the public interest. Therefore, these exemptions are hereby granted. The facility will operate, to the extent authorized herein, in conformity with the application, as amended, and the rules and regulations of the Commission (except as hereinafter exempted there from), and the provisions of the Act.

E. This renewed license is subject to the following additional condition for the protection of the environment:

Before engaging in additional construction or operational activities which may result in a significant adverse environmental impact that was not evaluated or that is significantly greater than that evaluated in the Final Environmental Statement and its Addendum dated November 1978, and the Final Supplemental Environmental Impact Statement dated August 2016, the licensee shall provide a written notification to the Director of the Office of Nuclear Reactor Regulation and receive written approval from that office before proceeding with such activities.

Am. 178 06/14/06

F. Deleted

3. The licensee shall notify the NRC in writing within 30 days after having accomplished item (b)1 above and include the status of those activities that have been or remain to be completed in item (b)2 above.

Am. 87 03/16/95

D. The facility requires exemptions from certain requirements of 10 CFR Part 50, 10 CFR Part 70, and 10 CFR Part 73. These include:

(a) Exemptions from certain requirements of Appendices G, H and J to 10 CFR Part 50, and to 10 CFR Part 73 are described in the Safety Evaluation Report and Supplement Numbers 1, 2, 3, and 5 to the Safety Evaluation Report.

Am. 181 08/28/09

(b) DELETED

DELETED

(c) ~~An exemption from the requirement of paragraph III.D of Appendix J to conduct the third Type A test of each ten-year service period when the plant is shutdown for the 10-year plant inservice inspections.~~

Am. 181 08/28/09

(d) DELETED

Am. 97 04/05/96

(e) An exemption was granted to remove the Main Steam Isolation Valves (MSIVs) from the acceptance criteria for the combined local leak rate test (Type B and C), as defined in the regulations of 10 CFR Part 50, Appendix J, Option B, Paragraph III.B. Exemption (e) is described in the safety evaluation accompanying Amendment No. 97 to this License.

These exemptions are authorized by law and will not endanger life or property or the common defense and security and are otherwise in the public interest. Therefore, these exemptions are hereby granted. The facility will operate, to the extent authorized herein, in conformity with the application, as amended, and the rules and regulations of the Commission (except as hereinafter exempted therefrom), and the provisions of the Act.

E. Before engaging in additional construction or operational activities which may result in a significant adverse environmental impact that was not evaluated or that is significantly greater than that evaluated in the Final Environmental Statement and its Addendum dated November 1978, and the Final Supplemental Environmental Impact Statement dated September 2016, the licensee shall provide a written notification to the Director of the Office of Nuclear Reactor Regulation and receive written approval from that office before proceeding with such activities.

5.5 Programs and Manuals

5.5.12 Safety Function Determination Program (SFDP) (continued)

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

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

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

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

c. The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered. When a loss of safety function is caused by the inoperability of a single Technical Specification support system, the appropriate Conditions and Required Actions to enter are those of the support system.

5.5.13 Primary Containment Leakage Rate Testing Program

a. This program shall establish 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, "Performance-Based Containment Leak-Testing Program," dated September 1995 as modified by the following exceptions:~~

Replace with INSERT

1. ~~NEI 94-01 - 1995, Section 9.2.3: The first Unit 1 Type A test performed after June 14, 1994 Type A test shall be performed no later than June 13, 2009.~~

(continued)

5.5 Programs and Manuals

5.5.13 Primary Containment Leakage Rate Testing Program (continued)

~~2.~~ ~~NEI 94-01 - 1995, Section 9.2.3: The first Unit 2 Type A test performed after December 8, 1993 Type A test shall be performed prior to startup following L2R12.~~

~~3.~~ The potential valve atmospheric leakage paths that are not exposed to reverse direction test pressure shall be tested during the regularly scheduled Type A test. The program shall contain the list of the potential valve atmospheric leakage paths, leakage rate measurement method, and acceptance criteria. This exception shall be applicable only to valves that are not isolable from the primary containment free air space.

b. The peak calculated primary containment internal pressure for the design basis loss of coolant accident, P_a, is 42.6 psig.

c. The maximum allowable primary containment leakage rate, L_a, at P_a, is 1.0% of primary containment air weight per day.

d. Leakage rate acceptance criteria are:

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

2. Air lock testing acceptance criteria are:

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

b) For each door, the seal leakage rate is ≤ 5 scf per hour when the gap between the door seals is pressurized to ≥ 10 psig.

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

(continued)

INSERT

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 exception:

ATTACHMENT 3

Risk Impact Assessment of
Extending the LSCS ILRT / DWBT Interval

LASALLE COUNTY STATION
UNITS 1 AND 2

Docket Nos. 50-373 and 50-374

Renewed Facility Operating License Nos. NPF-11 and NPF-18

126 pages follow

RM DOCUMENTATION NO. **LS-LAR-06** **REV: 1** **PAGE NO. 1**

STATION: LaSalle County Station (LSCS)

UNIT(s) AFFECTED: 1 & 2

TITLE: Risk Assessment for LSCS Regarding the ILRT (Type A) and DWBT Permanent Extension Request

SUMMARY:
LSCS is pursuing a License Amendment Request (LAR) to permanently extend the Type A Integrated Leak Rate Test (ILRT) and Drywell Bypass Test (DWBT) to 15 years.

The purpose of this document is to provide an assessment of the risk associated with implementing a permanent extension of the LSCS Unit 1 and Unit 2 containment ILRT and DWBT interval to 15 years. Rev. 1 revised the leakage rate used in the previous Level 3 work.

This is a Category I Risk Management Document in accordance with ER-AA-600-1012 Risk Management Documentation [24], which requires independent review and approval, ER-AA-600-1046 Risk Metrics – NOED and LAR [25] and ER-AA-600-1051, "Risk Assessment of Surveillance Test Frequency Changes" [26].

[ ] Review required after periodic update

[X] Internal RM Documentation **[ ] External RM Documentation**
Electronic Calculation Data Files:
Microsoft Excel LS_ILRT-Final Rev 1.xlsx, 07/06/2016, 2:55 PM, 268 KB

__Method of Review:__ [X] Detailed [ ] Alternate [ ] Review of External Document

This RM documentation supersedes: __**LS-LAR-06 Rev. 0**__

	Print		Sign		Date
Prepared by:	John Steinmetz	/	John E Steinmetz	/	7/19/16
Reviewed by: (App. A only)	Douglass Money	/	[signature]	/	7/2016
Reviewed by:	Felipe Gonzalez	/	[signature]	/	7/19/16
Reviewed by:	Grant Teagarden	/	Grant Teagarden	/	7/19/16
Reviewed by:	Don Vanover	/	Donald E Vanover	/	7/20/16
Approved by:	Eugene Kelly	/	Eugene M Kelly	/	7/21/16

TABLE OF CONTENTS

1.0 OVERVIEW

The risk assessment associated with implementing a permanent extension of the LSCS Unit 1 and Unit 2 Type A Integrated Leak Rate Test (ILRT) and Drywell Bypass Test (DWBT) interval to 15 years is described in this document.

1.1 PURPOSE

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

This analysis also provides a risk assessment of extending the plant's Drywell to Wetwell Bypass Leak Rate Test interval (DWBT) from 3 to 15 years. The DWBT risk assessment is performed in Appendix B separate from the Type A Test assessment in the main body of the calculation. The DWBT risk assessment is performed in accordance with the guidelines set forth in NEI 94-01, the methodology used in EPRI TR-1018243 [3], and the NRC regulatory guidance on the use of Probabilistic Risk Assessment (PRA) findings and risk insights in support of a licensee request for changes to a plant's licensing basis, Reg. Guide 1.174 [4]. Note, the DWBT surveillance test frequency is controlled under the LSCS Surveillance Frequency Control Program.

1.2 BACKGROUND

Revisions to 10CFR50, Appendix J (Option B) allow individual plants to extend the Integrated Leak Rate Test (ILRT) Type A surveillance testing requirements from three-in-ten years to at least once per ten years. The revised Type A frequency is based on an acceptable performance history defined as two consecutive periodic Type A tests at least 24 months apart in which the calculated performance leakage was less than the normal containment leakage of 1.0La (allowable leakage).

The basis for a 10-year test interval is provided in Section 11.0 of NEI 94-01, Revision 0, and was established in 1995 during development of the performance-based Option B to Appendix J. Section 11.0 of NEI 94-01 states that NUREG-1493 [6], "Performance-Based Containment Leak Test Program," provides the technical basis to support rulemaking to revise leakage rate testing requirements contained in Option B to Appendix J. The basis consisted of qualitative and quantitative assessments of the risk impact (in terms of increased public dose) associated with a range of extended leakage rate test intervals. To supplement the NRC's rulemaking basis, NEI undertook a similar study. The results of that study are documented in EPRI Report TR-104285 [2].

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

Earlier ILRT frequency extension submittals have used the EPRI TR-104285 [2] methodology to perform the risk assessment. In October 2008, EPRI 1018243 [3] was issued to develop a generic methodology for the risk impact assessment for ILRT interval extensions to 15 years using current performance data and risk informed guidance, primarily NRC Regulatory Guide 1.174 [4]. This more recent EPRI document considers the change in population dose, large early release frequency (LERF), and containment conditional failure probability (CCFP), whereas EPRI TR-104285 considered only the change in risk based on the change in population dose. This ILRT interval extension risk assessment for LSCS U1 and U2 employs the EPRI 1018243 methodology, with the affected System, Structure, or Component (SSC) being the primary containment boundary.

1.3 ACCEPTANCE CRITERIA

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

With regard to population dose, examinations of NUREG-1493 [6] and Safety Evaluation Reports (SERs) for one-time interval extension (summarized in Appendix G of EPRI TR-1018243 [3]) indicate a range of incremental increases in population dose(1) that have been accepted by the NRC. The range of incremental population dose increases is from ≤0.01 to 0.2 person-rem/yr and 0.002 to 0.46% of the total accident dose. The total doses for the spectrum of all accidents (Figure 7-2 of NUREG-1493) result in health effects that are at least two orders of magnitude less than the NRC Safety Goal Risk. Given these perspectives, the NRC SER on this issue [7] defines a "small" increase in population dose as an increase of ≤ 1.0 person-rem per year, or ≤1 % of the total population dose (when compared against the baseline interval of 3 tests per 10 years), whichever is less restrictive for the risk impact assessment of the extended ILRT intervals. This definition has been adopted for the LSCS analysis.

The acceptance criteria are summarized below.

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

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

2.0 METHODOLOGY

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

The six general steps of this assessment are as follows:

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

Furthermore,

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

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

3.0 GROUND RULES

The following ground rules are used in the analysis:

- The LSCS Level 1 and Level 2 internal events PRA models provide representative core damage frequency and release category frequency distributions to be utilized in this analysis. The technical adequacy of the PRA models are consistent with the requirements of Regulatory Guide 1.200 as relevant to this ILRT risk assessment. PRA adequacy is discussed in Appendix A.
- It is appropriate to use the LSCS internal events PRA model as a gauge to effectively describe the risk change attributable to the ILRT/DWBT extension. It is reasonable to assume that the impact from the ILRT/DWBT extension (with respect to percent increases in population dose) will not substantially differ if external events were to be included in the calculations; however, external events have been accounted for in the analysis based on the available information for LSCS.
- Dose results for the containment failures modeled in the PRA can be characterized by plant specific information provided in the Level 3 PRA Consequence Analysis (MACCS2 Model) [8] performed in support of the LSCS License Renewal Application Environmental Report containing the Severe Accident Mitigation Alternatives (SAMA) analysis [32].
- Accident classes describing radionuclide release end states and their definitions are consistent with the EPRI methodology [3] and are summarized in Section 4.2.
- The representative containment leakage for Class 1 sequences is 1La. Class 3 accounts for increased leakage due to Type A inspection failures.
- The representative containment leakage for Class 3a is 10La and for Class 3b sequences is 100La, based on the recommendations in the latest EPRI report [3] and as recommended in the NRC SE [7] on this topic. It should be noted that this is more conservative than the earlier previous industry ILRT extension requests, which utilized 35La for the Class 3b sequences.
- Based on the EPRI methodology and the NRC SE, the Class 3b sequences are categorized as LERF and the increase in Class 3b sequences is used as a surrogate for the ΔLERF metric.
- The impact on population doses from containment bypass scenarios is not altered by the proposed ILRT extension, but is accounted for in the EPRI methodology as a separate entry for comparison purposes. Since the containment bypass contribution to population dose is fixed, no changes on the conclusions from this analysis will result from this separate categorization.

- The reduction in ILRT frequency does not impact the reliability of containment isolation valves to close in response to a containment isolation signal.
- The use of the estimated 2043 population data incorporated in the LSCS Level 3 PRA Consequence Analysis [8] is appropriate for this analysis. Precise evaluations of the projected population would not significantly impact the quantitative results, nor would it change the conclusions.
- An evaluation of the risk impact of the ILRT on shutdown risk is addressed using the generic results from EPRI TR-105189 [9].
- The methodology to evaluate the impact of concurrently extending the DWBT interval is performed consistent with previous one-time ILRT/DWBT extensions for BWR Mark II containment types (Columbia [33], Limerick [34]), which have been approved by the NRC. Note, the previous LSCS one time ILRT extension license amendment request [35, 36] did not request a DWBT extension as the next DWBT test date aligned with the ILRT one-time 15 year extension test date.

4.0 INPUTS

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

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

4.1 GENERAL RESOURCES AVAILABLE

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

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

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

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

NUREG/CR-3539 [10]

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

NUREG/CR-4220 [11]

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

NUREG-1273 [12]

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

NUREG/CR-4330 [13]

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

> *"...the effect of containment leakage on overall accident risk is small since risk is dominated by accident sequences that result in failure or bypass of containment."*

EPRI TR-105189 [9]

The EPRI study TR-105189 is useful to the ILRT test interval extension risk assessment because this EPRI study provides insight regarding the impact of containment testing on shutdown risk. This study performed a quantitative evaluation (using the EPRI ORAM software) for two reference plants (a BWR-4 and a PWR) of the impact of extending ILRT and LLRT test intervals on shutdown risk.

The result of the study concluded that a small but measurable safety benefit (shutdown CDF reduced by 1.0E-8/yr to 1.0E-7/yr) is realized from extending the test intervals from 3 per 10 years to 1 per 10 years.

NUREG-1493 [6]

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

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

EPRI TR-104285 [2]

Extending the risk assessment impact beyond shutdown (the earlier EPRI TR-105189 study), the EPRI TR-104285 study is a quantitative evaluation of the impact of extending Integrated Leak Rate Test (ILRT) and (Local Leak Rate Test) LLRT test intervals on at-power public risk. This study combined IPE Level 2 models with NUREG-1150 [15] Level 3 population dose models to perform the analysis. The study also used the approach of NUREG-1493 [6] in calculating the increase in pre-existing leakage probability due to extending the ILRT and LLRT test intervals.

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

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

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

> *"These study results show that the proposed CLRT [containment leak rate tests] frequency changes would have a minimal safety impact. The change in risk determined by the analyses is small in both absolute and relative terms..."*

Release Category Definitions

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

TABLE 4.1-1

EPRI [2] CONTAINMENT FAILURE CLASSIFICATIONS

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

TABLE 4.1-1

EPRI [2] CONTAINMENT FAILURE CLASSIFICATIONS

CLASS	DESCRIPTION
8	Accidents in which the containment is bypassed (either as an initial condition or induced by phenomena) are included in Class 8. Changes in Appendix J testing requirements do not impact these accidents.

Calvert Cliffs Liner Corrosion Analysis [5]

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

EPRI 1018243 [3]

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

The risk impact assessment using the Jeffrey's Non-Informative Prior statistical method is further supplemented with a sensitivity case using expert elicitation performed to address conservatisms. The expert elicitation is used to determine the relationship between pre-existing containment leakage probability and magnitude. The results of

the expert elicitation process from this report are used as a separate sensitivity investigation for the LSCS analysis presented here in Section 6.2.

NRC Safety Evaluation Report [7]

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

4.2 PLANT-SPECIFIC INPUTS

The LSCS Unit 1 and Unit 2 specific information used to perform this ILRT interval extension risk assessment includes the following:

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

LSCS Unit 1 and Unit 2 Internal Events Core Damage Frequencies

The current LSCS Unit 1 and Unit 2 Internal Events PRA models of record are based on an event tree / linked fault tree model characteristic of the as-built, as-operated plant. Based on the results reported in Reference [16], the internal events Level 1 PRA core damage frequency (CDF) is 2.18E-06/yr for LSCS UNIT 2. Table 4.2-1 provides the CDF results by accident class.

No substantive differences exist between the LSCS Unit 1 and Unit 2 PRA models that are judged to affect the conclusions of the PRA. As such, no separate PRA quantification is conducted for Unit 1. Since the LSCS PRA Unit 2 PRA results are

judged representative of both Unit 1 and Unit 2, the ILRT/DWBT extension evaluation is considered applicable to both Unit 1 and Unit 2.

TABLE 4.2-1

SUMMARY OF LS214A CDF BY ACCIDENT SEQUENCE SUBCLASS

ACCIDENT CLASS DESIGNATOR	SUBCLASS	DEFINITION	MODEL 2014A (PER YR)
Class I	A	Accident sequences involving loss of inventory makeup in which the reactor pressure remains high.	6.05E-08
	B	Accident sequences involving a station blackout and loss of coolant inventory makeup. (Class IBE is defined as "Early" Station Blackout events with core damage at less than 5 hours. Class IBL is defined as "Late" Station Blackout events with core damage at greater than 5 hours.)	IBE 2.55E-08(1) IBL 1.85E-07
	C	Accident sequences involving a loss of coolant inventory induced by an ATWS sequence with containment intact.	1.78E-07
	D	Accident sequences involving a loss of coolant inventory makeup in which reactor pressure has been successfully reduced to 200 psi.	2.08E-07(1)
	E	Accident sequences involving loss of inventory makeup in which the reactor pressure remains high and DC power is unavailable.	(Grouped with Class IA)
Class II	A	Accident sequences involving a loss of containment heat removal with the RPV initially intact; core damage; core damage induced post containment failure.	9.97E-07
	L	Accident sequences involving a loss of containment heat removal with the RPV breached but no initial core damage; core damage induced post containment failure. (Not used)	
	T	Accident sequences involving a loss of containment heat removal with the RPV initially intact; core damage induced post high containment pressure	
	V	Class IIA and III except that the vent operates as designed; loss of makeup occurs at some time following vent initiation. Suppression pool saturated but intact.	
Class III (LOCA)	A	Accident sequences leading to core damage conditions initiated by vessel rupture where the containment integrity is not breached in the initial time phase of the accident.	9.40E-10
	B	Accident sequences initiated or resulting in small or medium LOCAs for which the reactor cannot be depressurized prior to core damage occurring.	2.14E-09
	C	Accident sequences initiated or resulting in medium or large LOCAs for which the reactor is a low pressure and no effective injection is available.	9.80E-09
	D	Accident sequences which are initiated by a LOCA or RPV failure and for which the vapor suppression system is inadequate, challenging the containment integrity with	2.70E-08

TABLE 4.2-1

SUMMARY OF LS214A CDF BY ACCIDENT SEQUENCE SUBCLASS

ACCIDENT CLASS DESIGNATOR	SUBCLASS	DEFINITION	MODEL 2014A (PER YR)
		subsequent failure of makeup systems.	
Class IV (ATWS)	A	Accident sequences involving failure of adequate shutdown reactivity with the RPV initially intact; core damage induced post containment failure.	4.10E-07
	L	Accident sequences involving a failure of adequate shutdown reactivity with the RPV initially breached (e.g. LOCA or SORV); core damage induced post containment failure.	
Class V	---	Unisolated LOCA outside containment.	8.20E-08
		Total	**2.18E-06**

LSCS Internal Events Release Category Frequencies

The Level 2 Model that is used for LSCS was developed to calculate the LERF contribution as well as the other release categories evaluated in the model. Table 4.2-2 summarizes the pertinent LSCS Unit 2 results in terms of release category (timing and magnitude). The total Large Early Release Frequency (LERF) which corresponds to the H/E release category in Table 4.2-1 was found to be 1.34E-07/yr. The total release frequency is 1.76E-06/yr. With a total CDF of 2.18E-06/yr, this corresponds to an "OK" release limited to normal leakage of 4.18E-07/yr.

TABLE 4.2-2

LSCS LEVEL 2 PRA MODEL RELEASE CATEGORIES AND FREQUENCIES

CATEGORY	FREQUENCY/YR(1)
Intact	4.18E-07
H/E – High Early (LERF)	1.34E-07
M/E – Medium Early	1.16E-07
L/E – Low Early	3.68E-07
LL/E – Low Low Early	0.00E+00
H/I – High Intermediate	1.93E-08
M/I – Medium Intermediate	9.46E-08

TABLE 4.2-2

LSCS LEVEL 2 PRA MODEL RELEASE CATEGORIES AND FREQUENCIES

CATEGORY	FREQUENCY/YR(1)
L/I – Low Intermediate	1.03E-06
LL/I – Low Low Intermediate	5.32E-10
H/L – High Late	0.00E+00
M/L – Medium Late	0.00E+00
L/L – Low Late	0.00E+00
LL/L – Low Low Late	0.00E+00
Total Release Frequency (Cont. Intact Frequency not included)	**1.76E-06**
Core Damage Frequency	**2.18E-06**

Note to Table 4.2-2:

(1) Frequency values are from quantification results (cutsets) and vary slightly from the results presented in Table 3.4-4 of the LSCS Summary Notebook [16].

LSCS Population Dose Information

The population dose is calculated by using data provided in the LSCS Level 3 PRA Consequence Analysis (MACCS2 Model) [8]. The LSCS population dose will be determined using the estimated population for the year 2043. This year is consistent with the year utilized for dose calculations documented in the LaSalle County Station Environmental Report, Appendix F Severe Accident Mitigation Alternatives (SAMA) Analysis [32]. As noted in the SAMA analysis:

> *"The population surrounding the LSCS site is estimated for the year 2043, the last year of projected operation for Unit 2 given a 20 year license extension (Unit 1 license expires in 2042). Estimating the population of the SAMA analysis region entailed three major steps: (1) determining the year 2000 permanent population within a 50-mile radius of LaSalle; (2) accounting for the transient population within the SAMA analysis region; and (3) projecting that permanent and transient population out to the year 2043 based on available population projection data." "The population distribution projection was based on year 2000 census data available via SECPOP2000 [31]."*

The population projections for the year 2043 are shown in Table 4.2-3 below. For additional detail regarding population estimates, see Appendix F of the License Renewal Application [32], which includes an assessment of 2010 census data.

TABLE 4.2-3

PROJECTED POPULATION DISTRIBUTION WITHIN A 50-MILE RADIUS OF LSCS(1)(2), YEAR 2043

SECTOR	0-10 MILES	10-20 MILES	20-30 MILES	30-40 MILES	40-50 MILES	50-MILE TOTAL
N	3,456	7,000	26,360	11,702	87,562	136,080
NNE	3,151	1,894	21,448	225,910	401,416	653,819
NE	5,606	11,510	15,612	455,348	628,691	1,116,767
ENE	941	16,099	37,905	245,127	338,890	638,962
E	643	6,548	60,524	8,673	94,937	171,325
ESE	2,705	2,530	3,405	7,122	39,094	54,856
SE	320	7,524	1,243	1,934	6,009	17,030
SSE	376	1,598	1,400	9,351	1,789	14,514
S	749	1,187	16,880	4,018	6,748	29,582
SSW	356	1,155	2,610	7,722	9,231	21,074
SW	736	24,853	4,370	6,197	21,642	57,798
WSW	363	1,584	3,116	5,560	13,448	24,071
W	1,574	1,544	11,641	6,235	5,539	26,533
WNW	774	9,123	38,359	5,464	11,692	65,412
NW	3,841	23,511	2,276	12,250	5,627	47,505
NNW	12,833	2,488	6,652	4,789	5,807	32,569
Total	**38,424**	**120,148**	**253,801**	**1,017,402**	**1,678,122**	**3,107,897**

Notes to Table 4.2-3:

(1) Population projection for 0-10 miles includes transients, special facilities, seasonal residents and permanent residents. Population projection for 10- 50 miles includes permanent residents only. This population projection is based on year 2000 census data.

(2) Population data shown in this table are reproduced from Table F.3-7 of the Severe Accident Mitigation Alternatives (SAMA) Analysis [32].

Radionuclide Release

Thirteen (13) different release categories were developed in the LSCS Level 2 PRA. These release categories represent radionuclide release severity and timing classification scheme shown in Table 4.2-4. The thirteen release categories were grouped into eight (8) release bins as shown in Table 4.2-5. For each of the eight release bins, a representative MAAP case was chosen based on a review of the Level 2 model cutsets and the dominant types of scenarios that contribute to the release bin. Further detail is presented in the LaSalle County Station Environmental Report, Appendix F [32].

TABLE 4.2-4

LEVEL 2 END STATE BINS: RADIONUCLIDE RELEASE SEVERITY AND TIMING CLASSIFICATION SCHEME (SEVERITY, TIMING)(1)(5)

RADIONUCLIDE RELEASE SEVERITY			RADIONUCLIDE RELEASE TIMING	
CLASSIFICATION CATEGORY	CS IODIDE % IN RELEASE		CLASSIFICATION CATEGORY	TIME OF INITIAL RELEASE(2) RELATIVE TO DECLARATION OF A GENERAL EMERGENCY
High (H)(4)	Greater than 10(4)		Late (L)	Greater than 24 hours
Moderate (M)	1 to 10		Intermediate (I)	E(3) to 24 hours
Low (L)	0.1 to 1		Early (E)	Less than E(3), (4) hours
Low-low (LL)	Less than 0.1			
No iodine (OK, Intact Containment)	Negligible			

Notes to Table 4.2-4:

(1) Thirteen (13) Level 2 End State Bins: H/E, H/I, H/L, M/E, M/I, M/L, L/E, L/I, L/L, LL/E, LL/I, LL/L, OK.

(2) The General Emergency declaration is accident sequence dependent and occurs when EALs are exceeded.

(3) Where E hours is less than the time when evacuation is effective (5 hours) for LSCS.

(4) Consistent with NUREG/CR-6595 [23].

(5) Table 4.2-4 is reproduced from Table F.3-14 from the Lasalle County Station Environmental Report, Appendix F [32].

TABLE 4.2-5

LSCS RELEASE CATEGORY BINS[2]

RELEASE CATEGORY	BIN
High Magnitude / Early Release (Accident Class V, Unisolated LOCA Outside Containment)	H/E-BOC
High Magnitude / Early Release (non-BOC release)	H/E
High Magnitude / Intermediate Release High Magnitude / Late Release[1]	H/I
Moderate Magnitude / Early Release	M/E
Moderate Magnitude / Intermediate Release Moderate Magnitude / Late Release[1]	M/I
Low Magnitude / Early Release Low-low Magnitude / Early Release[1]	L/E
Low Magnitude / Intermediate Release Low Magnitude / Late Release[1] Low-low Magnitude / Intermediate Release[1] Low-low Magnitude / Late Release[1]	L/I
Containment Intact	CI

Notes to Table 4.2-5:

(1) The release category frequency was calculated as negligible in the LSCS Level 2 PRA model. The release category is subsumed by the applicable bin.

(2) Table 4.2-4 is reproduced from Table F.3-16 from the Lasalle County Station Environmental Report, Appendix F [32].

0-50 Mile Dose Results

Dose (p-rem) for the LSCS release categories are shown in Table 4.2-6. This data is reproduced from Table F.3-20 MACCS2 Base Case Mean Results Unit 2 of the SAMA Analysis [32]. The SAMA Analysis population estimate for the year 2043, reactor power and containment size inputs are consistent with ILRT parameters. Therefore, no adjustments are required for population and reactor power parameters. As noted in the SAMA Analysis,

> *"The core inventory at the time of the accident is based on a plant-specific calculation (Exelon 2011). The core inventory represents bounding isotopic values for 100 effective full power days (EFPD) or 711 EFPD (end-of-cycle) for LSCS operating at 3489 MWt. The current licensed core power level is 3546 MWt based upon a recent power uprate associated with measurement uncertainty recapture (MUR). The MACCS2 model includes a reactor power scaling factor of 1.0163 (i.e., 3546 MWt/3489 MWt) to address the MUR power uprate to 3546 MWt."*

Containment Leakage Rate

The SAMA MACCS2 model dose results for an intact containment are based on a containment leakage rate of 0.5% per day. Tech Spec Amendment No. 147/133, Section 5.0 Administrative Controls, Subsection 5.5.13 Primary Containment Leakage Rate Testing Program provides an allowable leakage rate: "The peak calculated primary containment internal pressure for the design basis loss of coolant accident, Pa, is 42.6 psig. The maximum allowable primary containment leakage rate, La, at Pa, is 1.0% of primary containment air weight per day."

	CONTAINMENT LEAK RATE
LSCS SAMA Analysis	0.5%/day
LSCS 2016 ILRT Risk Assessment	1.0%/day

As shown above, the current L_a of 1% containment air weight/day is double the leakage rate used in the SAMA analysis. Therefore, a factor of 2 adjustment is applied to the SAMA dose. This x2 factor applies to the 'Intact Containment' release category only.

The other SAMA release categories involve a failure of containment such that an adjustment for containment leakage rate is not required.

TABLE 4.2-6

DOSE RESULTS BY SOURCE TERM (0-50 MILE RADIUS FROM LSCS SITE)

RELEASE CATEGORY	DOSE (P-REM)
H/E-BOC	1.61E+07
H/E	5.29E+06
H/I	5.66E+06
M/E	7.39E+06
M/I	3.86E+06
L/E	2.21E+05
L/I	7.09E+05
INTACT	4.34E+03(1)

Note to Table 4.2-6:

(1) The SAMA dose of 2.17E+03 person-rem is increased by a factor of 2 (2 * 2.17E+03 p-rem = 4.34E+03) to reflect a change to allowed TS leakage.

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

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

The probability of the EPRI Class 3a failures may be determined, consistent with the latest EPRI guidance [3], as the mean failure estimated from the available data (i.e., 2 "small" failures that could only have been discovered by the ILRT in 217 tests leads to a 2/217=0.0092 mean value). For Class 3b, consistent with latest available EPRI data, a

non-informative prior distribution is assumed for no "large" failures in 217 tests (i.e., 0.5/(217+1) = 0.0023).

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

The methodology states:

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

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

Consistent with the EPRI methodology [3], the change in the leak detection probability can be estimated by comparing the average time that a leak could exist without detection. For example, the average time that a leak could go undetected with a three-

year test interval is 1.5 years (3 yr / 2), and the average time that a leak could exist without detection for a ten-year interval is 5 years (10 yr / 2). This change would lead to a non-detection probability that is a factor of 3.33 (5.0/1.5) higher for the probability of a leak that is detectable only by ILRT testing, given a 10-year vs. a 3-yr interval. Correspondingly, an extension of the ILRT interval to fifteen years can be estimated to lead to about a factor of 5.0 (7.5/1.5) increase in the non-detection probability of a leak.

LSCS Past ILRT Results

The surveillance frequency for Type A testing in NEI 94-01 under option B criteria is at least once per ten years based on an acceptable performance history (i.e., two consecutive periodic Type A tests at least 24 months apart) where the calculated performance leakage rate was less than 1.0La, and in compliance with the performance factors in NEI 94-01, Section 11.3. Based on the successful completion of two consecutive ILRTs at LSCS Unit 1 and Unit 2, the current ILRT interval is once per ten years [37]. Note that the probability of a pre-existing leakage due to extending the ILRT interval is based on the industry-wide historical results as noted in the EPRI guidance document [3].

EPRI Methodology

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

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

The first three steps of the methodology deal with calculating the change in dose. The change in dose is the principal basis upon which the Type A ILRT interval extension was previously granted and is a reasonable basis for evaluating additional extensions. The fourth step in the methodology calculates the change in LERF and compares it to the guidelines in Regulatory Guide 1.174. Because the change in CDF for LSCS is minimal, the change in LERF forms the quantitative basis for a risk informed decision per current NRC practice, namely Regulatory Guide 1.174. The fifth step of the methodology calculates the change in containment failure probability, referred to as the conditional containment failure probability, CCFP. The NRC has identified a CCFP of less than 1.5% as the acceptance criteria for extending the Type A ILRT test intervals as the basis for showing that the proposed change is consistent with the defense in depth philosophy [7]. As such, this step suffices as the remaining basis for a risk informed decision per Regulatory Guide 1.174. Step 6 takes into consideration the additional risk due to external events, and Step 6 investigates the impact on results due to varying the assumptions associated with the liner corrosion rate and failure to visually identify pre-existing flaws.

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

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

The LSCS containment is a pressure-suppression BWR/Mark II type with a steel shell in the drywell region, including a portion below the concrete drywell floor. The shell is surrounded by concrete. The containment design employs the BWR Mark II concept of over-under pressure suppression with multiple downcomers connecting the reactor drywell to the waterfilled pressure suppression chamber. The primary containment is a

steel-lined, post-tensioned, concrete enclosure, housing the reactor and the suppression pool. This primary containment is entirely enclosed in the reinforced concrete reactor building which is the secondary containment structure.

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

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

<u>Assumptions</u>

1. Consistent with the Calvert Cliffs analysis, a half failure is assumed for the floor area. (See Table 4.4-1, Step 1.)
2. The two corrosion events over a 5.5 year data period are used to estimate the liner flaw probability in the Calvert Cliffs analysis and are assumed to be applicable to the LSCS containment analysis. These events, one at North Anna Unit 2 and one at Brunswick Unit 2, were initiated from the non-visible (backside) portion of the containment liner. It is noted that two additional events have occurred in recent years (based on a data search covering approximately 9 years documented in Reference [21]. In November 2006, the Turkey Point 4 containment building liner developed a hole when a sump pump support plate was moved. In May 2009, a hole approximately 3/8" by 1" in size was identified in the Beaver Valley 1 containment liner. For risk evaluation purposes, these two more recent events occurring over a 9 year period are judged to be adequately represented by the two events in the 5.5 year period of the Calvert Cliffs analysis incorporated in the EPRI guidance (See Table 4.4-1, Step 1).

3. Consistent with the Calvert Cliffs analysis, the steel liner flaw likelihood is assumed to double every five years. This is based solely on judgment and is included in this analysis to address the increased likelihood of corrosion as the steel liner ages (See Table 4.4-1, Steps 2 and 3). Sensitivity studies are included that address doubling this rate every two years and every ten years.
4. In the Calvert Cliffs analysis, the likelihood of the containment atmosphere reaching the outside atmosphere given that a liner flaw exists was estimated as 1.1% for the cylinder and dome region, and 0.11% (10% of the cylinder failure probability) for the basemat. These values were determined from an assessment of the containment fragility curve versus the ILRT test pressure. For LSCS the containment failure probabilities are conservatively assumed to be 10% for the drywell and wetwall outer walls and 1% for the basemat. It is noted that since the basemat for the LSCS Mark II containment is in the suppression pool, it is judged that failure of this area would not lead to LERF. Therefore the 1% probability is conservative. Sensitivity studies are included that increase and decrease the probabilities by an order of magnitude. (See Table 4.4-1, Step 4.)
5. Consistent with the Calvert Cliffs analysis, a 5% visual inspection detection failure likelihood given the flaw is visible and a total detection failure likelihood of 10% is used for the containment cylinder and head. For the containment basemat, 100% is assumed unavailable for visual inspection. The basemat assumption is conservative, as underwater inspection is performed every period (on average, every other outage) [38]. To date, all liner corrosion events have been detected through visual inspection (See Table 4.4-1, Step 5). Consistent with the Calvert Cliffs analysis that 85% of the interior wall surface is visible for inspection, LSCS estimates that at approximately 95% of the interior surface of the LSCS containment wall is inspectable [38]. Sensitivity studies are included that evaluate total detection failure likelihood of 5% and 15%, respectively.
6. Consistent with the Calvert Cliffs analysis, all non-detectable containment failures are assumed to result in early releases. This approach avoids a detailed analysis of containment failure timing and operator recovery actions.

TABLE 4.4-1
STEEL LINER CORROSION BASE CASE

STEP	DESCRIPTION	CONTAINMENT CYLINDER, CONE AND HEAD	CONTAINMENT BASEMAT
1	**Historical Steel Liner Flaw Likelihood** Failure Data: Containment location specific (consistent with Calvert Cliffs analysis).	Events: 2 2/(70 * 5.5) = **5.2E-3**	Events: 0 (assume 0.5 failure) 0.5/(70 * 5.5) = **1.3E-3**
2	**Age Adjusted Steel Liner Flaw Likelihood** During 15-year interval, assume failure rate doubles every five years (14.9% increase per year). The average for 5th to 10th year is set to the historical failure rate (consistent with Calvert Cliffs analysis).	<u>Year</u> / <u>Failure Rate</u> 1 / 2.1E-3 avg 5-10 / 5.2E-3 15 / 1.4E-2 **15 year average = 6.14E-3**	<u>Year</u> / <u>Failure Rate</u> 1 / 5.1E-4 avg 5-10 / 1.3E-3 15 / 3.6E-3 **15 year average = 1.54E-3**
3	**Flaw Likelihood at 3, 10, and 15 years** Uses age adjusted liner flaw likelihood (Step 2), assuming failure rate doubles every five years (consistent with Calvert Cliffs analysis – See Table 6 of Reference [5]).	**0.71% (1 to 3 years)** **4.06% (1 to 10 years)** **9.40% (1 to 15 years)** (Note that the Calvert Cliffs analysis presents the delta between 3 and 15 years of 8.7% to utilize in the estimation of the delta-LERF value. For this analysis, the values are calculated based on the 3, 10, and 15 year intervals.)	**0.18% (1 to 3 years)** **1.04% (1 to 10 years)** **2.42% (1 to 15 years)** (Note that the Calvert Cliffs analysis presents the delta between 3 and 15 years of 2.2% to utilize in the estimation of the delta-LERF value. For this analysis, the values are calculated based on the 3, 10, and 15 year intervals.)
4	**Likelihood of Breach in Containment Given Steel Liner Flaw** The failure probability of the containment cylinder and dome is assumed to be 10% (compared to 1.1% in the Calvert Cliffs analysis). The basemat failure probability is assumed to be a factor of ten less, 1% (compared to 0.11% in the Calvert Cliffs analysis).	**10%**	**1%**

TABLE 4.4-1

STEEL LINER CORROSION BASE CASE

STEP	DESCRIPTION	CONTAINMENT CYLINDER, CONE AND HEAD	CONTAINMENT BASEMAT
5	**Visual Inspection Detection Failure Likelihood** Utilize assumptions consistent with Calvert Cliffs analysis.	**10%** 5% failure to identify visual flaws plus 5% likelihood that the flaw is not visible (not through-cylinder but could be detected by ILRT) All events have been detected through visual inspection. 5% visible failure detection is a conservative assumption.	**100%** Cannot be visually inspected.
6	**Likelihood of Non-Detected Containment Leakage** (Steps 3 * 4 * 5)	**0.0071% (at 3 years)** =0.71% * 10% * 10% **0.0406% (at 10 years)** =4.06% * 10% * 10% **0.0940% (at 15 years)** =9.40% * 10% * 10%	**0.0018% (at 3 years)** =0.18% * 1% * 100% **0.0104% (at 10 years)** =1.04% * 1% * 100% **0.02.42% (at 15 years)** =2.42% * 1% * 100%

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

- At 3 years: 0.0071% + 0.0018% = 0.0089%
- At 10 years: 0.0406% + 0.0104% = 0.0510%
- At 15 years: 0.094% + 0.0242% = 0.1182%

5.0 RESULTS

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

TABLE 5.0-1

ACCIDENT CLASSES

ACCIDENT CLASSES (CONTAINMENT RELEASE TYPE)	DESCRIPTION
1	Containment Intact
2	Large Isolation Failures (Failure to Close)
3a	Small Isolation Failures (liner breach)
3b	Large Isolation Failures (liner breach)
4	Small Isolation Failures (Failure to seal –Type B)
5	Small Isolation Failures (Failure to seal—Type C)
6	Other Isolation Failures (e.g., dependent failures)
7	Failures Induced by Phenomena (Early and Late)
8	Bypass (Interfacing System LOCA)
CDF	**All CET End states (including very low and no release)**

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

- Core damage sequences in which the containment remains intact initially and in the long term (EPRI Class 1 sequences).
- Core damage sequences in which containment integrity is impaired due to random isolation failures of plant components other than those associated with Type B or Type C test components. For example, liner breach or bellows leakage, if applicable. (EPRI Class 3 sequences).
- Core damage sequences in which containment integrity is impaired due to containment isolation failures of pathways left "opened" following a plant

post-maintenance test. (For example, a valve failing to close following a valve stroke test. (EPRI Class 6 sequences). Consistent with the EPRI Guidance, this class is not specifically examined since it will not significantly influence the results of this analysis.

- Accident sequences involving containment bypass (EPRI Class 8 sequences), large containment isolation failures (EPRI Class 2 sequences), and small containment isolation "failure-to-seal" events (EPRI Class 4 and 5 sequences) are accounted for in this evaluation as part of the baseline risk profile. However, they are not affected by the ILRT frequency change.
- Class 4 and 5 sequences are impacted by changes in Type B and C test intervals; therefore, changes in the Type A test interval do not impact these sequences.

The steps taken to perform this risk assessment evaluation are as follows in sections 5.1 through 5.5:

Step 1 Quantify the base-line risk in terms of frequency per reactor year for each of the accident classes presented in Table 5.0-1.

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

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

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

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

Following Step 5, the results are summarized in section 5.6, external events are considered in Section 5.7 and the impact of containment overpressure is assessed in section 5.8.

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

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

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

For the assessment of ILRT impacts on the risk profile, the potential for pre-existing leaks is included in the model. (These events are represented by the Class 3 sequences in EPRI TR-1018243 [3]). Two failure modes were considered for the Class 3 sequences. These are Class 3a (small breach) and Class 3b (large breach).

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

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

TABLE 5.1-1

EPRI CLASS DOSE ASSIGNMENT FROM THE LS SAMA CONSEQUENCE MODEL

EPRI SCENARIO CLASS	LEVEL 2 ACCIDENT SEQUENCE BIN	DOSE (PERSON-REM)(3)
1	Containment Intact	4.34E+03
2	H/E(1) (Isolation Failure)	5.29E+06
7	All EPRI Class 7a through 7f Level 2 bins	1.44E+06(2)
7a (H/E)	H/E (minus EPRI Class 2 and EPRI Class 8)	5.29E+06
7b (H/I or H/L)	H/I	5.66E+06
7c (M/E)	M/E	7.39E+06
7d (M/I or M/L)	M/I	3.86E+06
7e (L/E or LL/E)	L/E	2.21E+05
7f (L/I, LL/I, L/L, or LL/L)	L/I	7.09E+05
8	H/E- ISLOCA,BOC	1.61E+07

Notes to Table 5.1-1:

(1) LS SAMA sequence H/E represents the highest containment failure (non-containment bypass) dose.

(2) Given that multiple LSCS discrete scenarios apply to the broader EPRI Class 7, the EPRI dose is based on a weighted average based on LSCS 2014A scenario frequencies. The weighted average dose is developed in Table 5.1-2.

(3) Values are the SAMA dose for the EPRI category as discussed in Section 4.2 and Table 4.2-6. No adjustments were required for population and power level. A factor of 2 is applied to the SAMA dose of 2.17E+03 to adjust for containment leakage rate of $1L_a$ versus $0.5L_a$ used in SAMA MAAP calculations for intact containment (2.17E+03 x 2.0 = 4.34E+03).

Class 1 Sequences

This group consists of all core damage accident progression bins for which the containment remains intact (modeled as Technical Specification Leakage). The frequency per year for these sequences is 3.93E-07/yr and is determined by subtracting all containment failure end states including the EPRI/NEI Class 3a and 3b frequency calculated below, from the total CDF. For this analysis, the associated maximum containment leakage for this group is 1La, consistent with an intact containment evaluation.

Class 1 = CDF – (EPRI Classes)

= 2.18E-06 – (9.69E-10 (Class 2) + 1.93E-08 (Class 3a) + 4.82E-09 (Class 3b) + 1.68E-06 (Class 7) + 8.20E-08 (Class 8))

= 3.93E-07/yr.

Class 2 Sequences

This group consists of large containment isolation failures. For LSCS, containment isolation failure sequences resulting in a large early release are the following: IA-084, IBE-084, IC-084, ID-084, IIIA-043, IIIB-043, and IIIC-043. The sum of the frequencies of these scenarios is 9.69E-10/yr. For LSCS one containment isolation failure sequence (IBL-084) was not included because this sequence is assessed as a non-early release. Sequence IBL-084 is included in the Class 7 sequences categorized as a H/I accident sequences.

Class 3 Sequences

This group represents pre-existing leakage in the containment structure (e.g., containment liner). The containment leakage for these sequences can be either small or large. In this analysis, a value of 10La was used for small pre-existing flaws and 100La for relatively large flaws.

The respective frequencies per year are determined as follows:

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

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

As described in Section 4.3, additional consideration is made to not apply these failure probabilities to those cases that are already considered LERF scenarios (i.e., the Class 2 and Class 8 contributions). Note that some portion of the EPRI Class 7 frequency also represents LERF scenarios, but these are conservatively not subtracted from that portion of CDF eligible for EPRI Class 3. The adjustment to exclude EPRI Class 2 and Class 8 is made on the frequency information as shown below:

Class_3a = 0.0092 * [CDF – (Class 2 + Class 8)]
= 0.0092 * [2.18E-06 – (9.69E-10 + 8.20E-08)]
= 1.93E-08/yr

Class_3b = 0.0023 * [CDF – (Class 2 + Class 8)]
= 0.0023 * [2.18E-06 – (9.69E-10 + 8.20E-08)]
= 4.82E-09/yr

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

Class 4 Sequences

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

Class 5 Sequences

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

Class 6 Sequences

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

Class 7 Sequences

This group consists of all core damage accident progression bins in which containment failure induced by severe accident phenomena occurs. Note that containment failure is not induced for containment bypass (BOC and ISLOCA) (EPRI Class 8) and isolation failure (EPRI Class 2) sequences as these are either the initiating event or a plant

condition, existing at the time of the initiating event. For this analysis, the associated radionuclide releases are based on the application of the Level 2 end states from the LSCS SAMA evaluation as described in Section 4.2. The Class 7 Sequences are all Level 2 Sequences except containment intact EPRI Class 1, the containment bypass (EPRI Class 8) and isolation failure (EPRI Class 2) sequences leading to a large early release. The failure frequency and population dose for each specific release category is shown below in Table 5.1-2. The total release frequency and total dose are then used to determine a weighted average person-rem. The resulting weighted average person-rem is the representative EPRI Class 7 dose in the subsequent analysis. Note that the total frequency and dose associated from this EPRI class does not change as part of the ILRT extension request.

TABLE 5.1-2

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

ACCIDENT CLASS	SAMA RELEASE CATEGORY	2014 PRA RELEASE FREQUENCY / YR(1)	POPULATION DOSE (50 MILES) PERSON-REM(2)	POPULATION DOSE RISK (50 MILES) (PERSON-REM / YR)(3)
EPRI #7a (H/E)	H/E (minus EPRI Class 2 and EPRI Class 8)	5.11E-08	5.29E+06	2.70E-01
EPRI #7b (H/I or H/L)	H/I	1.93E-08	5.66E+06	1.09E-01
EPRI #7c (M/E)	M/E	1.16E-07	7.39E+06	8.57E-01
EPRI #7d (M/I or M/L)	M/I	9.46E-08	3.86E+06	3.65E-01
EPRI #7e (L/E or LL/E)	L/E	3.68E-07	2.21E+05	8.13E-02
EPRI #7f (L/I, LL/I, L/L, or LL/L)	L/I	1.03E-06	7.09E+05	7.31E-01
Class 7 Total		**1.68E-06**	**1.44E+06(3)**	**2.41E+00**

Notes to Table 5.1-2:

(1) 2014 Release Frequency values obtained from Table 4.2-2. Example, Class 7f is the sum of L/I, LL/I, L/L and LL/L frequencies (1.03E-06 + 5.32E-10 + 0.0 + 0.0 = 1.03E-06)

(2) Population dose values obtained from Table 4.2-6 based on the SAMA release category.

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

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

Class 8 Sequences

This group represents sequences where containment bypass occurs. For this analysis, the frequency is determined from release categories Break Outside Containment (BOC) and ISLOCA Level 2 results. BOC and ISLOCA sequences contribute 6.34E-09/yr and 7.56E-08/yr respectively. The sum of each of these contributions is 8.20E-08/yr (listed in Table 4.2-1 for Accident Class V sequences).

Summary of Accident Class Frequencies

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

TABLE 5.1-3

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

ACCIDENT CLASSES (CONTAINMENT RELEASE TYPE)	DESCRIPTION	FREQUENCY (PER RX-YR)
1	No Containment Failure	3.93E-07
2	Large Isolation Failures (Failure to Close)	9.69E-10
3a	Small Isolation Failures (liner breach)	1.93E-08
3b	Large Isolation Failures (liner breach)	4.82E-09
4	Small Isolation Failures (Failure to seal –Type B)	N/A
5	Small Isolation Failures (Failure to seal—Type C)	N/A
6	Other Isolation Failures (e.g., dependent failures)	N/A
7	Failures Induced by Phenomena (Early and Late)	1.68E-06
8	Bypass (Interfacing System LOCA)	8.20E-08
CDF	**All CET End states (including very low and no release)**	**2.18E-06**

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

Plant-specific release analyses were performed to estimate the person-rem doses to the population within a 50-mile radius from the plant. The releases are based on information provided in the LaSalle County Station Environmental Report, Appendix F Severe Accident Mitigation Alternatives (SAMA) Analysis [32] as described in Section 4.2, and summarized in Table 4.2-6. The results of applying these releases to the EPRI containment failure classification are as follows:

Class 1 = 4.34E+03 person-rem (at 1.0La)(1)
Class 2 = 5.29E+06 person-rem(2)
Class 3a = 4.34E+03 person-rem x 10La = 4.34E+04 person-rem(3)
Class 3b = 4.34E+03 person-rem x 100La = 4.34E+05 person-rem(3)
Class 4 = Not analyzed
Class 5 = Not analyzed
Class 6 = Not analyzed
Class 7 = 1.44E+06 person-rem(4)
Class 8 = 1.61E+07 person-rem(5)

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

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(1) The Class 1, containment intact sequences, dose is assigned using a MAAP case representing 0.5%/day Tech Spec leakage with no RPV depressurization as described in LSCS SAMA Analysis [32]. A factor of 2 is applied to SAMA dose results to represent the current 1%/day Tech Spec leakage (1.0La).

(2) The Class 2, containment isolation failures, dose is approximated using MAAP case representing a LOCA event with successful depressurization but without successful make-up that leads to containment failure prior to RPV failure as described in LSCS SAMA Analysis [32].

(3) The Class 3a and 3b dose are related to the leakage rate as shown. This is consistent with the EPRI methodology.

(4) The Class 7 dose is assigned from the weighted average dose calculated from releases shown in Table 4.2-6 as detailed in Table 5.1-2 above.

(5) Class 8 sequences involve containment bypass failures; The MAAP case used is a H/E release with an unisolated LOCA outside of containment (Class V accident). The break location in this MAAP run does not account for scrubbing from the secondary containment that would occur from the dominant break locations for this release category bin.

TABLE 5.2-1

LSCS POPULATION DOSE ESTIMATES FOR POPULATION WITHIN 50 MILES

ACCIDENT CLASSES (CONTAINMENT RELEASE TYPE)	REPRESENTATIVE ACCIDENT SEQUENCE	DESCRIPTION	PERSON-REM (50 MILES)
1	Containment Intact	No Containment Failure (1 La)	4.34E+03
2	H/E (Non-BOC)	Large Isolation Failures (Failure to Close)	5.29E+06
3a	$10L_a$	Small Isolation Failures (liner breach)	4.34E+04
3b	$100L_a$	Large Isolation Failures (liner breach)	4.34E+05
4	N/A	Small Isolation Failures (Failure to seal –Type B)	NA
5	N/A	Small Isolation Failures (Failure to seal—Type C)	NA
6	N/A	Other Isolation Failures (e.g., dependent failures)	NA
7	See Table 5.1-2 (All releases except isolation, and bypass sequences)	Failures Induced by Phenomena (Early and Late)	1.44E+06
8	H/E (BOC)	Bypass (BOC and Interfacing System LOCA)	1.61E+07

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

TABLE 5.2-2

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

ACCIDENT CLASSES (CONT. RELEASE TYPE)	DESCRIPTION	PERSON-REM (0-50 MILES)	EPRI METHODOLOGY		EPRI METHODOLOGY PLUS CORROSION		CHANGE DUE TO CORROSION (PERSON-REM/YR) [(1)]
			FREQUENCY (1/YR)	PERSON-REM/YR (0-50 MILES)	FREQUENCY (1/YR)	PERSON-REM/YR (0-50 MILES)	
1	Containment Intact [(2)]	4.34E+03	3.93E-07	1.71E-03	3.93E-07	1.71E-03	-8.08E-07
2	Large Isolation Failures (Failure to Close)	5.29E+06	9.69E-10	5.13E-03	9.69E-10	5.13E-03	--
3a	Small Isolation Failures (liner breach)	4.34E+04	1.93E-08	8.37E-04	1.93E-08	8.37E-04	--
3b	Large Isolation Failures (liner breach)	4.34E+05	4.82E-09	2.09E-03	5.01E-09	2.17E-03	8.08E-05
7	Failures Induced by Phenomena (Early and Late)	1.44E+06	1.68E-06	2.41E+00	1.68E-06	2.41E+00	--
8	Containment Bypass (Interfacing System LOCA)	1.61E+07	8.20E-08	1.32E+00	8.20E-08	1.32E+00	--
CDF	**All CET end states**		**2.18E-06**	**3.743**	**2.18E-06**	**3.743**	**8.00E-05**

Notes to Table 5.2-2:

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

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

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

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

Risk Impact Due to 10-year Test Interval

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

Risk Impact Due to 15-Year Test Interval

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

TABLE 5.3-1

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

ACCIDENT CLASSES (CONT. RELEASE TYPE)	DESCRIPTION	PERSON-REM (0-50 MILES)	EPRI METHODOLOGY		EPRI METHODOLOGY PLUS CORROSION		CHANGE DUE TO CORROSION (PERSON-REM/YR)[1]
			FREQUENCY (1/YR)	PERSON-REM/YR (0-50 MILES)	FREQUENCY (1/YR)	PERSON-REM/YR (0-50 MILES)	
1	Containment Intact [2]	4.34E+03	3.37E-07	1.46E-03	3.36E-07	1.46E-03	-4.64E-06
2	Large Isolation Failures (Failure to Close)	5.29E+06	9.69E-10	5.13E-03	9.69E-10	5.13E-03	--
3a	Small Isolation Failures (liner breach)	4.34E+04	6.42E-08	2.79E-03	6.42E-08	2.79E-03	--
3b	Large Isolation Failures (liner breach)	4.34E+05	1.61E-08	6.97E-03	1.71E-08	7.43E-03	4.64E-04
7	Failures Induced by Phenomena (Early and Late)	1.44E+06	1.68E-06	2.41E+00	1.68E-06	2.41E+00	--
8	Containment Bypass (Interfacing System LOCA)	1.61E+07	8.20E-08	1.32E+00	8.20E-08	1.32E+00	--
CDF	**All CET end states**		**2.18E-06**	**3.750**	**2.18E-06**	**3.750**	**4.59E-04**

Notes to Table 5.3-1:

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

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

TABLE 5.3-2

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

ACCIDENT CLASSES (CONT. RELEASE TYPE)	DESCRIPTION	PERSON-REM (0-50 MILES)	EPRI METHODOLOGY		EPRI METHODOLOGY PLUS CORROSION		CHANGE DUE TO CORROSION (PERSON-REM/YR) [1]
			FREQUENCY (1/YR)	PERSON-REM/YR (0-50 MILES)	FREQUENCY (1/YR)	PERSON-REM/YR (0-50 MILES)	
1	Containment Intact [2]	4.34E+03	2.97E-07	1.29E-03	2.95E-07	1.28E-03	-1.08E-05
2	Large Isolation Failures (Failure to Close)	5.29E+06	9.69E-10	5.13E-03	9.69E-10	5.13E-03	--
3a	Small Isolation Failures (liner breach)	4.34E+04	9.65E-08	4.19E-03	9.65E-08	4.19E-03	--
3b	Large Isolation Failures (liner breach)	4.34E+05	2.41E-08	1.05E-02	2.66E-08	1.15E-02	1.08E-03
7	Failures Induced by Phenomena (Early and Late)	1.44E+06	1.68E-06	2.41E+00	1.68E-06	2.41E+00	--
8	Containment Bypass (Interfacing System LOCA)	1.61E+07	8.20E-08	1.32E+00	8.20E-08	1.32E+00	--
CDF	**All CET end states**		**2.18E-06**	**3.754**	**2.18E-06**	**3.755**	**1.06E-03**

Notes to Table 5.3-2:

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

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

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

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

For LSCS, 100% of the frequency of Class 3b sequences can be used as a conservative first-order estimate to approximate the potential increase in LERF from the ILRT interval extension (consistent with the EPRI guidance methodology and the NRC SE). Based on the original 3-in-10 year test interval assessment from Table 5.2-2, the Class 3b frequency is 5.01E-09/yr, which includes the corrosion effect of the containment liner. Based on a ten-year test interval from Table 5.3-1, the Class 3b frequency is 1.71E-08/yr; and, based on a fifteen-year test interval from Table 5.3-2, it is 2.66E-08/yr. Thus, the increase in the overall probability of LERF due to Class 3b sequences that is due to increasing the ILRT test interval from 3 to 15 years (including corrosion effects) is 2.16E-08/yr. Similarly, the increase in LERF due to increasing the interval from 10 to 15 years (including corrosion effects) is 9.46E-09/yr. As can be seen, even with the conservatisms included in the evaluation (per the EPRI methodology), the estimated change in LERF is well within Region III of Figure 4 of Reference [4] (i.e., the acceptance criteria for very small changes in LERF) when comparing the 15 year results to the original 3-in-10 year requirement.

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

Another parameter that can provide input into the decision-making process is the change in the conditional containment failure probability (CCFP). The change in CCFP is indicative of the effect of the ILRT on all radionuclide releases, not just LERF. The CCFP can be calculated from the results of this analysis. One of the difficult aspects of this calculation is providing a definition of the "failed containment." In this assessment,

the CCFP is defined such that containment failure includes all radionuclide release end states other than the intact state and, consistent with the EPRI guidance, the small isolation failures (Class 3a). The conditional part of the definition is conditional given a severe accident (i.e., core damage).

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

TABLE 5.5-1

LSCS ILRT CONDITIONAL CONTAINMENT FAILURE PROBABILITIES

CCFP 3 IN 10 YRS	CCFP 1 IN 10 YRS	CCFP 1 IN 15 YRS	$\Delta CCFP_{15-3}$	$\Delta CCFP_{15-10}$
81.08%	81.63%	82.07%	0.99%	0.43%

Note to Table 5.5-1:

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

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

5.6 SUMMARY OF INTERNAL EVENTS RESULTS

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

TABLE 5.6-1

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

EPRI CLASS	DOSE PER-REM	BASE CASE 3 IN 10 YEARS CDF (1/YR)	BASE CASE 3 IN 10 YEARS PERSON-REM/YR	EXTEND TO 1 IN 10 YEARS CDF (1/YR)	EXTEND TO 1 IN 10 YEARS PERSON-REM/YR	EXTEND TO 1 IN 15 YEARS CDF (1/YR)	EXTEND TO 1 IN 15 YEARS PERSON-REM/YR
1	4.34E+03	3.93E-07	1.71E-03	3.36E-07	1.46E-03	2.95E-07	1.28E-03
2	5.29E+06	9.69E-10	5.13E-03	9.69E-10	5.13E-03	9.69E-10	5.13E-03
3a	4.34E+04	1.93E-08	8.37E-04	6.42E-08	2.79E-03	9.65E-08	4.19E-03
3b	4.34E+05	5.01E-09	2.17E-03	1.71E-08	7.43E-03	2.66E-08	1.15E-03
7	1.44E+06	1.68E-06	2.41E+00	1.68E-06	2.41E+00	1.68E-06	2.41E+00
8	1.61E+07	8.20E-08	1.32E+00	8.20E-08	1.32E+00	8.20E-08	1.32E+00
Total		**2.18E-06**	**3.743**	**2.18E-06**	**3.750**	**2.18E-06**	**3.755**

		BASE CASE 3 IN 10 YEARS	EXTEND TO 1 IN 10 YEARS	EXTEND TO 1 IN 15 YEARS
ILRT Dose Rate (person-rem/yr) from 3a and 3b		3.01E-03	1.02E-02	1.57E-02
Delta Total Dose Rate[(1)]	From 3 yr	---	6.96E-03	1.23E-02
	From 10 yr	---	---	5.33E-03
3b Frequency (LERF)		5.01E-09	1.71E-08	2.66E-08
Delta 3b LERF	From 3 yr	---	1.21E-08	2.16E-08
	From 10 yr	---	---	9.46E-09
CCFP %		81.08%	81.63%	82.07%
Delta CCFP %	From 3 yr	---	0.56%	0.99%
	From 10 yr	---	---	0.43%

Note to Table 5.6-1:

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

TABLE 5.6-2

LSCS ILRT EXTENSION COMPARISON TO ACCEPTANCE CRITERIA

Figure of Merit ->	**ΔLERF**	**ΔPerson-rem/yr**	**ΔCCFP**
Results (3/10yrs to 1/15yrs)	2.16E-8/yr	1.23E-02/yr (0.33%)	0.99%
Acceptance Criteria	**<1.0E-6/yr**	**<1.0 person-rem/yr <u>or</u> <1.0%**	**<1.5%**

5.7 EXTERNAL EVENTS CONTRIBUTION

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

5.7.1 <u>Past LSCS External Event Analyses And Models</u>

5.7.1.1 Fire Risk

For LSCS, there are two fire models that quantified Fire CDF prior to the most recent application specific 2015 Unit 2 Fire PRA model:

- Risk Methods Integration and Evaluation Program (RMIEP) Analysis [28]
- LSCS 2008 Fire PRA Update [19]

The RMIEP Analysis was the first internal fire analysis developed for LSCS by Sandia National Laboratories and published in 1993. RMIEP evaluated Fire CDF with a calculated value of 3.21E-05/yr for Unit 2. LERF was not calculated.

Subsequent to the RMIEP Analysis, the LSCS 2008 Fire PRA evaluation was developed as an interim implementation of NUREG/CR-6850 [18] methods and also only considered Fire CDF and a limited scope of work (e.g., Multi-Compartment Analysis not included). The Unit 1 and 2 Fire CDF were determined to be 8.91E-06/yr and 9.41E-06/yr, respectively [19].

The latest Fire PRA model (LS214A) was approved as an application specific model for Unit 2 in November 2015 [30] to support a peer review. The Unit 2 CDF is 9.48E-05/yr and LERF is 5.82E-06/yr. A peer review was conducted in December 2015. Similar to the 2008 model, the LSCS 2015 Fire PRA is considered an interim implementation of NUREG/CR-6850. A graded approach has been applied to the task of updating the Exelon Fire Probabilistic Risk Assessments. This approach has been used given some aspects of the FPRA methodology per NUREG/CR-6850 are continuing to evolve and because of the iterative nature of development of a PRA precluded the prediction of exact resources required to address all modeling issues in one update.

5.7.1.2 Seismic Risk

Bounding seismic CDF values from the NRC have been made public as part of the development of a generic issue report. Table D-1 of Risk Assessment for NRC GI-199 [27] lists the postulated core damage frequencies using the updated 2008 USGS Seismic Hazard Curves. The weakest link model using the curve for LSCS resulted in a CDF of 3.7E-06/yr and is the highest CDF presented in the Risk Assessment for NRC GI-199 for LSCS. This CDF value is utilized for the bounding external events assessment provided here. The NRC study did not calculate LERF. Previous to this GI-199 risk assessment, the NRC calculated for LSCS Unit 2 a seismic CDF of 6.0E-7/yr in RMIEP [28].

5.7.1.3 Other External Event Risk

External hazards were evaluated in the LSCS Individual Plant Examination of External Events (IPEEE) submittal [22] in response to the NRC IPEEE Program (Generic Letter 88-20, Supplement 4) [20]. The IPEEE Program was a one-time review of external hazard risk and was limited in its purpose to the identification of potential plant vulnerabilities and the understanding of associated severe accident risks.

In addition to internal fires and seismic events, the LSCS IPEEE submittal [22] analyzed high winds, floods, and other (HFO) external hazards. The IPEEE analysis was

accomplished by reviewing the NRC's Risk Methods Integration and Evaluation Program (RMIEP) analysis [28]. As reported in the IPEEE submittal, military and industrial facilities accidents, pipeline accidents and release of chemicals in onsite storage were eliminated (screened as insignificant) based on the analyses and information which was presented in the LSCS FSAR.

Bounding analysis in the RMIEP study was performed for an aircraft impact, external flooding, transportation accidents, turbine missiles and winds and tornadoes. The IPEEE concluded, "Due to the conservatism introduced in the bounding analysis by neglecting the plant system failures and consequence analysis and due to the low CDFs resulting from these bounding analyses, the RMIEP study concluded that none of the external events listed above presented a significant contributor to the plant risk."

It should be noted that the current LSCS Updated Final Safety Analysis Report (UFSAR) [29] documents conformance to the General Design Criteria Criterion 2 - Design Bases for Protection Against Natural Phenomena and Criterion 4 - Environmental and Missile Design Bases.

5.7.2 LSCS Fire Risk Discussion

The most recent (2015) LSCS Fire PRA has not been approved for general use in quantified risk applications because there are several areas of conservatism in the current treatment that result in skewing the total reported CDF towards the upper bound. While the fire analysis did yield a CDF and LERF, the intent of the analysis was to move closer to meeting most capability category II ASME/ANS RA-SA-2009 standard requirements. It is expected that further modeling refinements will be made to more realistically model fire scenarios. An update to address peer review comments and to further refine modeling scenarios is on-going. The attributes of the fire PRA that lead to conservative quantification values are summarized below.

Attributes of Fire PRA

Fire PRAs are useful tools to identify design or procedural items that could be clear areas of focus for improving the safety of the plant. Fire PRAs use a structure and quantification technique similar to that used in the internal events PRA. Historically, since less attention has been paid to fire PRAs, conservative modeling is common in a number of areas of the fire analysis to provide a "bounding" methodology for fires. This concept is contrary to the base internal events PRA which has had more analytical development and is closer to a realistic (i.e., not conservative) assessment of the plant.

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

Initiating Events:	The frequency of fires and their severity are generally conservatively overestimated. A revised NRC fire events database indicates the trend toward both lower frequency and less severe fires. This trend reflects the improved housekeeping, reduction in transient fire hazards, and other improved fire protection steps at nuclear utilities.
System Response:	Fire protection measures such as sprinklers, CO_2, and fire brigades may be given minimal (conservative) credit in their ability to limit the spread of a fire. Therefore, the severity of the fire and its impact on requirements is exacerbated. In addition, cable routings are typically characterized conservatively because of the lack of data regarding the routing of cables or the lack of the analytic modeling, including circuit analysis to represent the different routings. This leads to limited credit for balance of plant systems that are extremely important in CDF mitigation.
Sequences:	Sequences may subsume a number of fire scenarios to reduce the analytic burden. The subsuming of initiators and sequences is done to envelope those sequences included. This causes additional conservatism.
Fire Modeling:	Fire damage and fire propagation are conservatively characterized. Fire modeling presents bounding approaches regarding the fire immediate effects (e.g., all cables in a tray are always failed for a cable tray fire) and fire propagation.

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

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

In any event, the reported 2015 FPRA CDF value is 9.48E-5/yr or approximately a factor of 43 higher than the current internal events CDF value of 2.18E-06/yr. The fire CDF is judged to be conservative given the methods employed in developing the fire PRA for LSCS when compared to the best estimate CDF and LERF values obtained from the internal events models.

<u>Fire PRA CDF Impact to Class 3b LERF</u>

The Fire PRA Core Damage Frequency has a dominant release category of Class II Decay Heat Removal Sequences which constitute 65.3% of the Fire CDF. This compares to the Full Power Internal Events (FPIE) PRA Class II Decay Heat Removal contribution of 45.7% of CDF. Class II contributes 9.97E-07/yr of the FPIE CDF of 2.18E-06 as shown in Table 4.2-1. EPRI Class 3b LERF due to containment leakage can be expressed in the following formula:

> Frequency 3b = [3b conditional failure probability] x [CDF - (CDF with independent LERF + CDF that cannot cause LERF)]

The Class II Decay Heat Removal sequences would be non-LERF with the exception of sequences where operators fail to declare a General Emergency (GSEP) condition when entry conditions are met. The probability of this operator action failure is 5E-02 in the LSCS PRA model. Conservatively assuming 95% of Class II Core Damage Frequency is CDF that "cannot cause LERF" due to timing, the Fire CDF and FPIE CDF can be compared by subtracting 95% of Class II contributions to CDF from both.

Fire CDF Class II contribution to be removed = 9.48E-05/yr * 0.653 * 0.95 = 5.88E-05/yr

Fire CDF with 95% of Class II contribution removed = 9.48E-05/yr – 5.88E-05/yr
= 3.60E-05/yr.

FPIE CDF Class II contribution to be removed = 2.18E-06/yr * 0.457 * 0.95 = 9.46E-07/yr

FPIE CDF with 95% of Class II contribution removed = 2.18E-06/yr – 9.46E-07/yr
= 1.23E-06/yr.

The Fire CDF can be compared to FPIE CDF with Class II non-LERF sequence contribution removed. Since ILRT delta risk is primarily a function of CDF, it could be assumed that the total impact from the ILRT fire risk contribution is bounded by assuming a factor of 29.2 (3.60E-05/yr ÷ 1.23E-06/yr) compared to the internal events evaluation alone. However, the fire multiplier will be applied towards the full FPIE CDF (2.18E-06/yr) which includes Class II non-LERF sequences. To better represent the impact of fire risk for the ILRT assessment where non-LERF frequencies can be excluded, the fire multiplier of 29.2 can be discounted by the ratio of FPIE CDF with Class II sequences removed to the full FPIE CDF (i.e., 1.23E-06/yr ÷ 2.18E-06/yr = 0.564) to give a fire multiplier of 16.5.

5.7.3 LSCS Seismic Risk Discussion

A quantifiable seismic PRA model for LSCS has not yet been approved for general use in risk applications. LSCS seismic CDF was estimated to be 6E-7/yr. in the NRC's Risk Methods Integration and Evaluation Program (RMIEP) analysis [28]. However, more recent information is available from the NRC. The Risk Assessment for NRC GI-199

[27], Table D-1 lists the postulated core damage frequencies using the updated 2008 USGS Seismic Hazard Curves. The weakest link model using the curve for LSCS resulted in a CDF of 3.7E-06/yr. The seismic CDF is a factor of 1.70 compared to the FPIE CDF (3.7E-06/yr ÷ 2.18E-06/yr). Given this, it is reasonable to assume that the total impact from seismic risk can be approximated by assuming a factor of 1.70 compared to the internal events evaluation alone. Using a FPIE PRA LERF value of 1.34E-07/yr and multiplying by 1.70 for seismic, gives a LERF estimate for the seismic PRA model of 2.27E-07/yr.

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

5.7.4 Other External Events Discussion

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

- Military and industrial facilities accidents
- Pipeline accidents
- Release of chemicals in onsite storage
- Aircraft impact
- External flooding
- Transportation accidents
- Turbine missiles
- High winds and tornadoes

The LSCS IPEEE analysis of these events was accomplished by reviewing the NRC's Risk Methods Integration and Evaluation Program (RMIEP) Analysis [28]. Based upon this review, it was concluded that none of the external events listed above presented a significant contributor to the plant risk.

Based on the other external events being low risk contributors and the fact that the ILRT extension would not significantly change the risk from these types of events, the increase in the LSCS other external events risk due to the ILRT extension is much less than that calculated for internal events.

5.7.5 External Events Impact Summary

In summary, the combination of the fire and seismic CDF values described above results in an external events bounding risk estimates of 9.48E-05/yr (fire) and 3.70E-06/yr (seismic). This compares to the internal events CDF of 2.18E-06/yr. Since the change in risk for the ILRT risk impact is a function of CDF, a multiplier will be used for the initial bounding assessment for the external events impact. As discussed previously, the multiplier for the fire risk impact is calculated with Class II sequences that "cannot result in LERF" removed. Since individual seismic CDF class contributions are unknown, the seismic multiplier comparing total seismic CDF and FPIE CDF is applied.

Table 5.7-1 summarizes the estimated bounding external events CDF contribution for LSCS (with no adjustments made to account for Class II contributions).

TABLE 5.7-1

LSCS EXTERNAL EVENTS CONTRIBUTOR SUMMARY

EXTERNAL EVENT INITIATOR GROUP	CDF (1/YR)	LERF (1/YR)
Seismic	3.70E-06	2.27E-07[1]
Internal Fire (without adjustments for Class II sequences)	9.48E-05	5.82E-06[2]
High Winds	Screened	Screened
Other Hazards	Screened	Screened
Total For External Events (for initiators with CDF/LERF available)	**9.85E-05**	**6.05E-06**
Internal Events CDF (for comparison)	2.18E-06	1.34E-07

Notes to Table 5.7-1:

(1) As noted in Section 5.7.2, seismic LERF is assumed to be the ratio of seismic CDF to FPIE CDF multiplied by FPIE LERF.

(2) The 2015 Fire PRA [30] calculated a LERF value of 5.82E-06/yr.

As noted earlier, the 3b contribution is approximately proportional to CDF. An increase in CDF would likely lead to higher 3b frequency and assumed LERF. The Fire CDF contributors were adjusted to remove class II scenarios where an "early" declaration of a General Emergency was declared. The sequence contribution for the Seismic CDF is unknown and no adjustments were made. To determine a suitable multiplier of external CDF to internal event CDF, a multiplier is developed for each external event group (i.e., fire and seismic) and then added together to address both contributors, as shown in Table 5.7-2. For fire contribution, the adjusted CDF (i.e., class II scenarios removed) ratio of fire and FPIE is multiplied by the portion of FPIE CDF that the fire contribution can act upon (i.e., ratio of adjusted FPIE CDF and unadjusted FPIE CDF). For seismic, the ratio of unadjusted CDF (i.e., seismic and FPIE) is used.

TABLE 5.7-2
LSCS EXTERNAL EVENTS TO INTERNAL EVENTS CDF COMPARISON

EXTERNAL EVENT INITIATOR GROUP	CDF (1/YR)	EXTERNAL EVENT ADJUSTED CDF (1/YR)	FPIE INITIATOR GROUP	FPIE CDF (1/YR)	INITIAL MULTIPLIER	APPLICABLE MULTIPLIER PORTION[2]
Fire	9.48E-05	3.60E-05[1]	FPIE (without class II sequences)	1.23E-06[1]	29.2	16.50
Seismic	3.70E-06	NA	FPIE (unadjusted)	2.18E-06	1.70	1.70
External Event to FPIE CDF Multipler						**18.2**

Notes to Table 5.7-2:

(1) Class II sequence CDF contributions that "cannot result in LERF" are not included.

(2) The initial fire multiplier is reduced by a factor of 0.564 (i.e., 1.23E-06/yr / 2.18E-06/yr) because the intial fire multiplier is only applicable to a portion of the unadjusted FPIE CDF (2.18E-06/yr). The initial seismic multiplier is based on the unadjusted FPIE CDF and therefore no further reduction factor is applied.

5.7.6 External Events Impact on ILRT Extension Assessment

The EPRI Category 3b frequency for the 3-per-10 year, 1-per-10 year, and 1-per-15 year ILRT intervals are shown in Table 5.6-1 as 5.01E-09/yr, 1.71E-08/yr, and 2.66E-08/yr, respectively. Using an external events multiplier of 18.2 for LSCS, the change in the LERF risk measure due to extending the ILRT from 3-per-10 years to 1-per-15 years, including both internal and external hazards risk, is estimated as shown in Table 5.7-3.

TABLE 5.7-3

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

	3B FREQUENCY (3-PER-10 YR ILRT)	3B FREQUENCY (1-PER-10 YEAR ILRT)	3B FREQUENCY (1-PER-15 YEAR ILRT)	LERF INCREASE(1)
Internal Events Contribution	5.01E-09	1.71E-08	2.66E-08	2.16E-08
External Events Contribution (Internal Events x 18.2)	9.12E-08	3.12E-07	4.84E-07	3.93E-07
Combined (Internal + External)	**9.62E-08**	**3.29E-07**	**5.11E-07**	**4.15E-07**

Note to Table 5.7-3:

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

The other acceptance criteria for the ILRT extension risk assessment can be similarly derived using the multiplier approach. The results between the 3-in-10 year interval and the 15 year interval compared to the acceptance criteria are shown in Table 5.7-4. As can be seen, the impact from including the external events contributors would not change the conclusion of the risk assessment. That is, the acceptance criteria are all met such that the estimated risk increase associated with permanently extending the ILRT surveillance interval to 15 years has been demonstrated to be small. Note that a bounding analysis for the total LERF contribution follows Table 5.7-4 to demonstrate that the total LERF value for LSCS is less than 1.0E-05/yr consistent with the requirements for a “Small Change” in risk of the RG 1.174 acceptance guidelines.

TABLE 5.7-4

COMPARISON TO ACCEPTANCE CRITERIA INCLUDING EXTERNAL EVENTS CONTRIBUTION FOR LSCS

CONTRIBUTOR	ΔLERF	ΔPERSON-REM/YR	ΔCCFP
Internal Events	2.16E-08/yr	1.23E-02/yr (0.33%)	0.99%
External Events	3.93E-07/yr	2.24E-01/yr (0.33%)	0.99%
Total	**4.15E-07/yr**	**2.36E-01/yr (0.33%)**	**0.99%**
Acceptance Criteria	**<1.0E-6/yr**	**<1.0 person-rem/yr** **or** **<1.0%**	**<1.5%**

The 4.15E-07/yr increase in LERF due to the combined internal and external events from extending the ILRT frequency from 3-per-10 years to 1-per-15 years falls within Region II between 1.0E-7 to 1.0E-6 per reactor year ("Small Change" in risk) of the RG 1.174 acceptance guidelines. Per RG 1.174, when the calculated increase in LERF due to the proposed plant change is in the "Small Change" range, the risk assessment must also reasonably show that the total LERF is less than 1.0E-5/yr. Similar bounding assumptions regarding the external event contributions that were made above are used for the total LERF estimate.

From Table 4.2-2, the total LERF due to postulated internal event accidents is 1.34E-07/yr for LSCS. As discussed in Sections 5.7.2, the total LERF estimate for the Fire PRA model is 5.82E-06/yr. As discussed in Sections 5.7.3, the total LERF estimate for the Seismic PRA model is 2.27E-07/yr. The total LERF values for LSCS are shown in Table 5.7-5.

TABLE 5.7-5

IMPACT OF 15-YR ILRT EXTENSION ON LERF FOR LSCS

LERF CONTRIBUTOR	(1/YR)
Internal Events LERF	1.34E-07
Fire LERF	5.82E-06
Seismic LERF	2.27E-07
Internal Events LERF due to ILRT (at 15 years) (1)	2.16E-08
External Events LERF due to ILRT (at 15 years) (1)	3.93E-07 [Internal Events LERF due to ILRT * 18.2]
Total	**6.60E-06/yr**

Note to Table 5.7-6:

(1) Including age adjusted steel liner corrosion likelihood as reported in Table 5.7-3.

As can be seen, the estimated upper bound LERF for LSCS is estimated as 6.60E-06/yr. This value is less than the RG 1.174 requirement to demonstrate that the total LERF due to internal and external events is less than 1.0E-05/yr.

5.8 CONTAINMENT OVERPRESSURE IMPACTS ON CDF

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

LSCS does not credit containment overpressure for the mitigation of design basis accidents. The LSCS BWR/5 ECCS pumps are designed to be able to pump saturated fluid. UFSAR [29] Section 6.3.2.2.6 ECCS Pumps NPSH notes "The ECCS pump specifications are such that the NPSH requirements for HPCS, LPCS and LPCI are met with the containment at atmospheric pressure and the suppression pool at saturation temperature. Calculations were performed to evaluate ECCS NPSH requirements post DBA-LOCA."

Based on the ECCS pump designs, the LSCS PRA does not require containment pressurization above atmospheric conditions for successful ECCS injection. Therefore

an increase in the containment leakage (e.g., EPRI Class 3b) that prevents containment overpressurization would have no affect on successful ECCS injection.

It is noted that the PRA model includes failure of ECCS injection following containment failure from overpressurization. The following is from the LSCS PRA Event Tree Notebook [39]:

> *"In the event that containment integrity has been breached due to failure to control containment pressure and temperature or due to containment venting, there could be detrimental effects on the ability to continue core cooling. Such effects could include the following:*
>
> - *Harsh reactor building environmental conditions;*
> - *Steam binding of ECCS pumps; or*
> - *Failure at penetrations of injection systems due to containment catastrophic failure.*
>
> *The general condition associated with these long term sequences where containment integrity or venting is challenged is that residual core heat generation has decayed to a very low level and CRD is adequate as an RPV make-up source."*

Thus, as currently modeled in the LSCS PRA, increased EPRI Class 3b frequency that precludes containment overpressurization would provide some risk benefit for CDF by preventing the assumed failure of ECCS pumps at containment failure. Given the low probability that a long term loss of decay heat removal scenario would contribute to an "early" release, any impacts associated with NPSH from an undetected containment crack is determined to be negligible.

6.0 SENSITIVITIES

6.1 SENSITIVITY TO CORROSION IMPACT ASSUMPTIONS

The results in Tables 5.2-2, 5.3-1, and 5.3-2 show that including corrosion effects calculated using the assumptions described in Section 4.4 does not significantly affect the results of the ILRT extension risk assessment. In any event, sensitivity cases were developed to gain an understanding of the sensitivity of the results to the key parameters in the corrosion risk analysis. The time for the flaw likelihood to double was adjusted from every five years to every two and every ten years. The failure probabilities for the wall and basemat were increased and decreased by an order of magnitude. The total detection failure likelihood was adjusted from 10% to 15% and 5%. The results are presented in Table 6.1-1. In every case, the impact from including the corrosion effects is minimal. Even the upper bound estimates with conservative assumptions for all of the key parameters yield increases in LERF due to corrosion of only 9.22E-08/yr. The results indicate that even with conservative assumptions, the conclusions from the base analysis would not significantly change.

TABLE 6.1-1

STEEL LINER CORROSION SENSITIVITY CASES FOR LSCS

AGE (STEP 3 IN THE CORROSION ANALYSIS)	CONTAINMENT BREACH (STEP 4 IN THE CORROSION ANALYSIS)	VISUAL INSPECTION & NON-VISUAL FLAWS (STEP 5 IN THE CORROSION ANALYSIS)	INCREASE IN CLASS 3B FREQUENCY (LERF) FOR ILRT EXTENSION FROM 3 IN 10 TO 1 IN 15 YEARS (PER YEAR)	
			TOTAL INCREASE	INCREASE DUE TO CORROSION
Base Case Doubles every 5 yrs	Base Case (10% Wall, 1% Basemat)	Base Case (10% Wall, 100% Basemat)	2.16E-08	2.29E-09
Doubles every 2 yrs	Base	Base	2.45E-08	5.21E-09
Doubles every 10 yrs	Base	Base	2.12E-08	1.92E-09
Base	Base	15% Wall	2.25E-08	3.20E-09
Base	Base	5% Wall	2.07E-08	1.38E-09
Base	100% Wall, 10% Basemat	Base	4.22E-08	2.29E-08
Base	1.0% Wall, 0.1% Basemat	Base	1.95E-08	2.29E-10
LOWER BOUND				
Doubles every 10 yrs	1.0% Wall, 0.1% Basemat	5% Wall, 100% Basemat	1.94E-08	1.15E-10
UPPER BOUND				
Doubles every 2 yrs	100% Wall, 10% Basemat	15% Wall, 100% Basemat	9.22E-08	7.29E-08

6.2 EPRI EXPERT ELICITATION SENSITIVITY

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

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

TABLE 6.2-1
EPRI EXPERT ELICITATION RESULTS

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

The summary of results using the expert elicitation values for probability of containment leakage (including corrosion) is provided in Table 6.2-2. As mentioned previously, probability values are those associated with the magnitude of the leakage used in the base case evaluation (10La for small and 100La for large). The expert elicitation process produces a relationship between probability and leakage magnitude in which it is possible to assess higher leakage magnitudes that are more reflective of large early releases; however, these evaluations are not performed in this particular study.

The net effect is that the reduction in the multipliers shown above also leads to a dramatic reduction on the calculated increases in the LERF values. As shown in Table 6.2-2, the increase in the overall value for LERF due to Class 3b sequences that is due to increasing the ILRT test interval from 3 to 15 years is just 4.36E-09/yr. Similarly, the increase due to increasing the interval from 10 to 15 years is just 2.28E-09/yr. As such, if the expert elicitation probabilities of occurrence are used instead of the non-informative prior estimates, the change in LERF is well within the range of a "very small" change in risk when compared to the current 1-in-10, or baseline 3-in-10 year requirement. Additionally, as shown in Table 6.2-2, the increase in dose rate and CCFP are similarly reduced to much smaller values. The results of this sensitivity study are judged to be more indicative of the actual risk associated with the ILRT extension than the results from the assessment as dictated by the values from the EPRI methodology [3], and yet are still conservative given the assumption that all of the Class 3b contribution is considered to be LERF.

TABLE 6.2-2

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

		BASE CASE 3 IN 10 YEARS		EXTEND TO 1 IN 10 YEARS		EXTEND TO 1 IN 15 YEARS	
EPRI CLASS	**DOSE PER-REM**	**CDF (1/YR)**	**PERSON-REM/YR**	**CDF (1/YR)**	**PERSON-REM/YR**	**CDF (1/YR)**	**PERSON-REM/YR**
1	4.34E+03	4.09E-07	1.77E-03	3.88E-07	1.68E-03	3.72E-07	1.61E-03
2	5.29E+06	9.69E-10	5.13E-03	9.69E-10	5.13E-03	9.69E-10	5.13E-03
3a	4.34E+04	8.14E-09	3.53E-04	2.71E-08	1.18E-03	4.07E-08	1.77E-03
3b	4.34E+05	7.04E-10	3.06E-04	2.79E-09	1.21E-03	5.07E-09	2.20E-03
7	1.44E+06	1.68E-06	2.41E+00	1.68E-06	2.41E+00	1.68E-06	2.41E+00
8	1.61E+07	8.20E-08	1.32E+00	8.20E-08	1.32E+00	8.20E-08	1.32E+00
Total		**2.18E-06**	**3.741**	**2.18E-06**	**3.742**	**2.18E-06**	**3.744**
ILRT Dose Rate from 3a and 3b		6.59E-04		2.39E-03		3.97E-03	
Delta Total Dose Rate[(1)]	From 3 yr	---		1.64E-03		3.15E-03	
	From 10 yr	---		---		1.51E-03	
3b Frequency (LERF)		7.04E-10		2.79E-09		5.07E-09	
Delta 3b LERF	From 3 yr	---		2.09E-09		4.36E-09	
	From 10 yr	---		---		2.28E-09	
CCFP %		80.88%		80.97%		81.08%	
Delta CCFP %	From 3 yr	---		0.10%		0.20%	
	From 10 yr	---		---		0.10%	

Note to Table 6.2-2:

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

7.0 CONCLUSIONS

Based on the results from Section 5 and the sensitivity calculations presented in Section 6, the following conclusions regarding the assessment of the plant risk are associated with permanently extending the Type A ILRT and DWBT test frequency to fifteen years:

- Reg. Guide 1.174 [4] provides guidance for determining the risk impact of plant-specific changes to the licensing basis. Reg. Guide 1.174 defines "very small" changes in risk as resulting in increases of CDF below 1.0E-06/yr and increases in LERF below 1.0E-07/yr. "Small" changes in risk are defined as increases in CDF below 1.0E-05/yr and increases in LERF below 1.0E-06/yr. Since the ILRT extension was demonstrated to have negligible impact on CDF for LSCS, the relevant criterion is LERF. The increase in internal events LERF resulting from a change in the Type A ILRT test interval for the base case with corrosion included is 2.16E-08/yr (see Table 5.6-1). In using the EPRI Expert Elicitation methodology, the change is estimated as 4.36E-09/yr (see Table 6.2-2). Both of these values fall within the very small change region of the acceptance guidelines in Reg. Guide 1.174.
- The change in dose risk for changing the Type A test frequency from three-per-ten years to once-per-fifteen-years, measured as an increase to the total integrated dose risk for all internal events accident sequences for LSCS, is 1.23E-02 person-rem/yr (0.33%) using the EPRI guidance with the base case corrosion included (Table 5.6-1). The change in dose risk drops to 3.15E-03 person-rem/yr (0.08%) when using the EPRI Expert Elicitation methodology (Table 6.2-2). The values calculated per the EPRI guidance are all lower than the acceptance criteria of ≤1.0 person-rem/yr or <1.0% person-rem/yr defined in Section 1.3.
- The increase in the conditional containment failure frequency from the three in ten year interval to one in fifteen years including corrosion effects using the EPRI guidance (see Section 5.5) is 0.99%. This value drops to 0.20% using the EPRI Expert Elicitation methodology (see Table 6.2-2). Both of these values are below the acceptance criteria of less than 1.5% defined in Section 1.3.
- To determine the potential impact from external events, a bounding assessment from the risk associated with external events was performed utilizing available information. As shown in Table 5.7-4, the total increase in LERF due to internal events and the bounding external events assessment is 4.15E-07/yr. This value is in Region II of the Reg. Guide 1.174 acceptance guidelines.
- As shown in Table 5.7-5, the same bounding analysis indicates that the total LERF from both internal and external risks is 6.60E-06/yr which is

less than the Reg. Guide 1.174 limit of 1.0E-05/yr given that the ΔLERF is in Region II (small change in risk).

- Including age-adjusted steel liner corrosion effects in the ILRT assessment was demonstrated to be a small contributor to the impact of extending the ILRT interval for LSCS.
- A DWBT risk analysis documented in Appendix B provides key metric values that, in combination with ILRT results, would not change the ILRT related conclusions described above. The DWBT values for an interval change from the original 3-in-10 years to 15 years are compared below to the ILRT base case with corrosion. These DWBT values are developed in Appendix B and reported in Appendix B, Section B.5.

  Delta CDF = 1.09E-09/yr (ILRT increase = negligible)

  Delta LERF = 3.86E-09/yr (ILRT increase = 2.16E-08/yr)

  Delta Dose = 1.64E-02 p-rem/yr (ILRT increase = 1.23E-02 p-rem/yr)

  Delta CCFP = 0.01% (ILRT increase = 0.99%)

  The DWBT CDF increase is less than 0.1% of Base CDF. The DWBT values for LERF and CCFP are significantly below the ILRT values. Although the DWBT person-rem dose rate increase is higher than the ILRT dose rate increase, the DWBT dose rate increase is approximately two orders of magnitude below the acceptance criteria of ≤1.0 person-rem/yr.

Therefore, increasing the ILRT and DWBT intervals on a permanent basis to a one-in-fifteen year frequency is not considered to be significant since it represents only a small change in the LSCS risk profiles.

<u>Previous Assessments</u>

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

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

of containment penetrations, ILRTs also test the integrity of the containment structure.

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

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APPENDIX A
PRA TECHNICAL ADEQUACY

A PRA TECHNICAL ADEQUACY

A.1 OVERVIEW

A technical Probabilistic Risk Assessment (PRA) analysis is presented in this report to help support an extension of the LSCS Unit 1 and Unit 2 containment Type A test integrated leak rate test (ILRT) interval to fifteen years.

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

- Identify the parts of the PRA used to support the application
  - SSCs, operational characteristics affected by the application and how these are implemented in the PRA model.
  - A definition of the acceptance criteria used for the application.
- Identify the scope of risk contributors addressed by the PRA model
  - If not full scope (i.e. internal and external), identify appropriate compensatory measures or provide bounding arguments to address the risk contributors not addressed by the model.
- Summarize the risk assessment methodology used to assess the risk of the application
  - Include how the PRA model was modified to appropriately model the risk impact of the change request.
- Demonstrate the Technical Adequacy of the PRA
  - Identify plant changes (design or operational practices) that have been incorporated at the site, but are not yet in the PRA model and justify why the change does not impact the PRA results used to support the application.
  - Document peer review findings and observations that are applicable to the parts of the PRA required for the application, and for those that have not yet been addressed justify why the significant contributors would not be impacted.
  - Document that the parts of the PRA used in the decision are consistent with applicable standards endorsed by the Regulatory Guide. Provide justification to show that where specific requirements in the standard are not met, it will not unduly impact the results.

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

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

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

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

A.2 PRA MODEL EVOLUTION AND PEER REVIEW SUMMARY

A.2.1 Introduction

The 2014A versions of the LSCS PRA models are the most recent evaluations of the Unit 1 and Unit 2 risk profile at LSCS for internal event challenges. The LSCS PRA modeling is highly detailed, including a wide variety of initiating events, modeled

systems, operator actions, and common cause events. The PRA model quantification process used for the LSCS PRA is based on the event tree / fault tree methodology, which is a well-known methodology in the industry.

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

PRA Maintenance and Update

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

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

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

- Documentation of the PRA model, PRA products, and bases documents.
- The approach for controlling electronic storage of Risk Management (RM) products including PRA update information, PRA models, and PRA applications.
- Guidelines for updating the full power, internal events PRA models for Exelon nuclear generation sites.
- Guidance for use of quantitative and qualitative risk models in support of the On-Line Work Control Process Program for risk evaluations for maintenance tasks (corrective maintenance, preventive maintenance, minor maintenance, surveillance tests and modifications) on systems, structures, and components (SSCs) within the scope of the Maintenance Rule (10 CFR 50.65(a)(4)).

In accordance with this guidance, regularly scheduled PRA model updates nominally occur on an approximately 4-year cycle; longer intervals may be justified if it can be shown that the PRA continues to adequately represent the as-built, as-operated plant. The 2014A models were completed in November of 2015.

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

A.2.2 Plant Changes Not Yet Incorporated into the PRA Model

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

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

A.2.3 Consistency with Applicable PRA Standards

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

An independent PRA peer review was conducted under the auspices of the BWR Owners Group in 2000, following the Industry PRA Peer Review process [A.2]. This peer review included an assessment of the PRA model maintenance and update process. The overall conclusion of the LSCS PRA Peer Review was positive, and the PRA Peer Review Team stated that the LSCS PRA can be effectively used to support applications involving risk-informed applications. The "Facts and Observations" for LSCS have been evaluated and addressed by the LSCS PRA Program as part of the last three PRA updates. There were no “A” Facts and Observations and fifteen “B” Facts and Observations identified in the 2000 PRA Peer Review report [A.11]. All fifteen “B” Facts and Observations have been resolved by model changes (thirteen in the 2003 update and two in the 2011 update). No outstanding “A” or “B” priority F&Os remain.

Following the 2006C model issuance, a Peer Review of the LSCS Unit 2 PRA model was performed using the NEI 05-04 [A.7] process and the ASME/ANS PRA Standard [A.3] along with the NRC clarifications provided in Regulatory Guide 1.200, Revision 1 [A.8]. This Peer Review was documented in a report dated July 2008 [A.9]. There were 13 findings and 62 suggestions as a result of the 2008 Peer Review. Of these 13 findings, 11 findings were associated with SRs that were not met. The other 2 findings were associated with SRs meeting CC 1. Table A-1 provides a listing of the findings related to the 11 SR ‘not met’ findings, the SR criteria, and resolution of the findings.

Exelon has completed a self-assessment of the PRA compared with the ASME/ANS PRA Standard [A.4] and RG 1.200 Rev. 2 [A.1] in preparation for the 2014 PRA update. Results of the self-assessment are shown below. Table A-2 provides a listing of the SRs 'not met', the SR criteria, and the impact to the ILRT application. The results of the LSCS Self-Assessment [A.10] and the resolution during the 2014 PRA update are as follows:

Number of Supporting Requirements at Capability Category II or higher or Deemed Not Applicable	309 of 326
Number of Gaps Identified for 2011A PRA (Capability Category at I or Not Met)	17
Number of Gaps Resolved for 2014 Model	8
Number of Gaps deferred, awaiting NRC or EPRI guidance or clarification, or judged to be of low Safety Significance	9

This leaves 9 of the 326 Supporting Requirements that are not yet fully at Capability Category II in the latest (2014) LSCS PRA model.

- There are two (2) Supporting Requirements (DA-C6, DA-C10) that are not met.
- There are four (4) Supporting Requirements (SC-A5, HR-D3, DA-C7, DA-C8) that are met at Category I only.
- There are three (3) Supporting Requirements (IFSO-A3, IFSN-A7, IFQU-A3) which are not met, but are related to Internal Flooding which was not within the scope of the 2014 update.

A.2.4 Applicability of Peer Review Findings and Observations

The remaining set of findings from the 2008 peer review [A.9] and 2014 self-assessment [A.10] related to the current ANS/ASME PRA Standard [A.4] for internal events and internal flood associated with supporting requirements that are 'not met' are described in Tables A-1 and A-2 with their impact on this application noted.

TABLE A-1

STATUS OF GAPS TO CAPABILITY CATEGORY I FROM THE 2008 PEER REVIEW

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	SR REQUIREMENT	CURRENT STATUS / COMMENT	IMPORTANCE TO APPLICATION
HR-A1-01	This requirement [HR-A1] is probably met during the review to determine the pre-initiator HEPs, however, there is no list or documentation showing the procedures. Similarly for HR-A2, the documentation does not provide evidence of the procedures reviewed. It just says procedures are reviewed.	HR-A1 HR-A2	"HR-A1: For equipment modeled in the PRA, IDENTIFY, through a review of procedures and practices, those test and maintenance activities that require realignment of equipment outside its normal operational or standby status. HR-A2: IDENTIFY, through a review of procedures and practices, those calibration activities that if performed incorrectly can have an adverse impact on the automatic initiation of standby safety equipment."	Closed: Reviewed procedures applicable to pre-initiators are found in Table B-5 and Appendix C of the HRA Notebook, LS-PSA-004.	None
HR-G6-01	Table 5.1-2 summarizes the post-initiator HEPs in tabular form, but no consistency check is discussed in the analysis.	HR-G6	CHECK the consistency of the post-initiator HEP quantifications. REVIEW the HFEs and their final HEPs relative to each other to check their reasonableness given the scenario context, plant history, procedures, operational practices, and experience.	Closed: A consistency check was conducted and is documented in LS-PRA-014 LSCS HRA Notebook. A HEP Consistency Review is found in Appendix D of the HRA notebook. The validation of the HEPs is performed primarily through the following mechanisms: • Independent review of the detailed HEP quantifications and results by both PRA and operations personnel. • Consistent use of HRA procedures that are designed to meet the requirements of the ASME/ANS PRA Standard. In addition to the above, Appendix D documents an additional HEP consistency review based on comparison of the final HEPs and associated characteristics. The post-initiator HEPs are reviewed for reasonableness in comparison to others when considering influencing factors such	None

TABLE A-1

STATUS OF GAPS TO CAPABILITY CATEGORY I FROM THE 2008 PEER REVIEW

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	SR REQUIREMENT	CURRENT STATUS / COMMENT	IMPORTANCE TO APPLICATION
				as the time available, stress, level of execution complexity, operator familiarity with the action, etc. Table D-1 of the HRA Notebook documents the HEP reasonableness review. The results of the review indicate that the HEPs in the LSCS analysis are internally consistent. It should also be noted that use of the HRA calculator supports consistency in HEP probabilities. The human error probabilities are also consistent with typical industry values for similar actions and are reasonable estimates of the reliability of the human interface at LSCS for the severe accident scenarios. The process leading to this conclusion included: Operator interviews, Observations of simulator scenarios, review of LSCS Abnormal, Severe Accident and associated procedures, and critical performance shaping factors based on the interviews with the operating crew and trainers."	
IE-D3-01	The Summary Notebook includes information that attempts to identify the key sources of uncertainty in the initiating event analysis. However, with the changes to eliminate "key" from the SR definition, this SR cannot be considered met.	AS-C3 DA-E3 HR-I3 IE-D3 IF-F3 LE-G4 QU-E2	DOCUMENT the key assumptions and key sources of uncertainty associated with the Accident Sequence, Data, Human Reliability, Internal Flooding, and LERF analysis. For LERF analysis including results and important insights from sensitivity studies. For Quantification, IDENTIFY key assumptions made in the development of the PRA model.	Closed: The 2009 ASME/ANS Standard revised requirements have eliminated the need to "EVALUATE the sensitivity of the results…" that existed in the ASME PRA Standard (2005). The following has been deleted from the 2005 ASME/ANS PRA Standard: "EVALUATE the sensitivity of the results to key model uncertainties and key assumptions using sensitivity analyses (1) For specific applications, key assumptions and parameters should be	None

TABLE A-1

STATUS OF GAPS TO CAPABILITY CATEGORY I FROM THE 2008 PEER REVIEW

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	SR REQUIREMENT	CURRENT STATUS / COMMENT	IMPORTANCE TO APPLICATION
				examined both individually and in logical combinations. " It should be noted that the uncertainty analysis documented in LS-PRA-014 LSCS HRA Notebook documents key assumptions and sources of uncertainty. The ILRT LAR risk assessment identifies key assumptions and sources of uncertainty and documents a number of sensitivities to address uncertainties.	
LE-F3-01	"This requirement is not met since the SR is tied back to items identified in QU-E2 and QU-E4. Since QU-E2 and QU-E4 are not met yet, this SR is also not met.	LE-F3	IDENTIFY contributors to LERF and characterize LERF uncertainties consistent with the applicable requirements of Tables 4.5.8-2(d) and 4.5.8-2(e).	Closed: The uncertainty analysis was updated as part of the 2011A PRA Update and is captured in the LSCS Summary Document LS-PSA-08 Rev. 8. The uncertainty analysis follows the current industry guidance as documented in NUREG-1855 and associated EPRI reports.	None
LE-G6-01	See finding IE-D3-01 and QU-F4-01 findings related to QU-E2 and QU-E4."	LE-G6	DOCUMENT the quantitative definition used for significant accident than the definition used in Section 2, JUSTIFY the alternative.	Closed: See resolution to QU-F6-01, below.	None
QU-D1a-01	Document the definition in the Level 2 notebook for significant accident progression sequence.	QU-D1a	REVIEW a sample of the significant accident sequences/cutsets sufficient to determine that the logic of the cutset or sequence is correct.	Closed: LS-PSA-014, LSCS PRA Quantification Notebook and LS-PSA-015, LSCS PRA Summary Notebook document reviews of the significant accident sequences and cutsets. The Summary Notebook summarizes the significant accident sequences that represent 95% of the total CDF and LERF from the L1 and L2 PRA. The top 39 accident sequences represent 95% of the	None

TABLE A-1

STATUS OF GAPS TO CAPABILITY CATEGORY I FROM THE 2008 PEER REVIEW

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	SR REQUIREMENT	CURRENT STATUS / COMMENT	IMPORTANCE TO APPLICATION
				calculated CDF at a truncation of 1E-12/yr. The top 10 L2 accident sequences represent 95% of the calculated LERF at a truncation of 1E-12/yr. Each of these accident sequences were reviewed for correctness and reasonableness. System and train level cutsets are included in all of the system notebooks. The cutsets were reviewed for accuracy with changes made, compared among trains, and compared between the units. A review of dominant and non-dominant cutsets from the integrated results was performed prior to model finalization. An investigation of the current model cutsets compared to the previous model cutsets was performed and changes were confirmed to be appropriate.	
QU-D4-01	ER-AA-600-1015 Attachment 2, Review of Updated PRA Model, contains specific guidance for reviewing a sample of accident sequences/cutsets to determine that the logic of the cutset or sequence is correct. Sections 6.3.1 and 6.5 of LS-PSA-014 discuss the top 10 CDF and LERF cutsets, respectively. The model appears to be reasonable based on these discussions. However, the top 10 CDF cutsets represent only about 31% of the total CDF. The review team felt that additional cutsets, representing more % of the total CDF should be reviewed and discussed.	QU-D4	REVIEW a sampling of nonsignificant accident cutsets or sequences to determine they are reasonable and have physical meaning.	Closed: A review of non-significant cutsets was performed on the PRA model and is documented in LS-PSA-014, LSCS Quantification Notebook, Section 1. The review was performed following guidance provided in ER-AA-600-1015 Attachment 2.	None

TABLE A-1

STATUS OF GAPS TO CAPABILITY CATEGORY I FROM THE 2008 PEER REVIEW

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	SR REQUIREMENT	CURRENT STATUS / COMMENT	IMPORTANCE TO APPLICATION
QU-E4-01	Clarification of RG1.200 issued in July 2007 modifies this requirement to read "For each source of model uncertainty and related assumption identified in QU-E1 and QU-E2, respectively, IDENTIFY how the PRA model is affected (e.g., introduction of a new basic event, changes to basic event probabilities, change in success criterion, introduction of a new initiating event)". Given that the requirements QU-E2 have not been met, this SR is not met. The changes to this SR as identified by the NRC via a Federal Register Notice in July of 2007 indicate that for all sources of uncertainty, respectively, IDENTIFY how the PRA model is affected. FINDING: Once items for QU-E1 and QU-E2 are identified per the new requirements, identify how the PRA model is affected (e.g. introduction of a new basic event, changes to basic event probabilities, change in success criterion, introduction of a new initiating event) for each item.	QU-E4	PROVIDE an assessment of the impact of the key model uncertainties on the results of the PRA.	Closed: The uncertainty analysis was updated as part of the 2011A PRA Update and is captured in the LSCS Summary Document LS-PSA-08 Rev. 8. A qualitative uncertainty analysis is provided in LS-PSA-08 Appendix B. LS-PSA-08 Appendix D documents, as recommended by NUREG-1855, quantitative sensitivity studies were performed on Human Error Probability (HEP) and Common Cause Failure (CCF) probabilities. In addition, Appendix D documents an additional 15 quantitative sensitivity studies addressing additional key model uncertainties. See response to F&O QU-F4-01 for additional information.	None
QU-F4-01	Documentation for the characterization of the sources of model uncertainty and related assumptions (as identified in QU-E4) was not provided since the most recent requirements for QU-E4 were not met.	QU-F4	DOCUMENT key assumptions and key sources of uncertainty, such as: possible optimistic or conservative success criteria, suitability of the reliability data, possible modeling uncertainties (modeling limitations due to the method selected), degree of completeness in the selection of	Closed: The uncertainty analysis was updated as part of the 2011A PRA Update and is captured in the LSCS Summary Document LS-PSA-08 Rev. 8. The analysis characterizes the LSCS FPIE PRA model uncertainty consistent with the NRC guidance in NUREG-1855 to satisfy the ASME/ANS PRA Standard as endorsed by R.G. 1.200 Rev. 2.	None

TABLE A-1

STATUS OF GAPS TO CAPABILITY CATEGORY I FROM THE 2008 PEER REVIEW

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	SR REQUIREMENT	CURRENT STATUS / COMMENT	IMPORTANCE TO APPLICATION
			initiating events, possible spatial dependencies, etc.	According to NUREG-1855 and the NRC workshop on modeling uncertainty held in May 2009, the characterization of modeling uncertainties in the base PRA model documentation is sufficient to meet the ASME/ANS PRA Standard Capability Category II Supporting Requirements (SRs) defined by the combined ASME/ANS PRA Standard.	
QU-F6-01	A documented quantitative definition for significant basic event, significant cutset, and significant accident sequence was not provided.	QU-F6	DOCUMENT the quantitative definition used for significant basic event, significant cutset, and significant accident sequence. If other than the definition used in Section 2, JUSTIFY the alternative.	Closed: Definition added to the LS-PSA-014 LSCS Quantification Notebook conforming to definitions used in Section 2. The notebook documents truncation limits are set in accordance with QU-B2 and QU-B3 to assure significant sequences and accident sequences are not eliminated. As documented in the Quantification Notebook, an investigation was carried out to assure, important recovery action combinations were not eliminated by use of this truncation value, and no important accident sequences were eliminated by the use of this truncation value. A sensitivity study is performed of the calculated CDF and number of cutsets that result as the truncation level is decreased. The sensitivity study was performed with the final logic model and the final database.	None

TABLE A-1

STATUS OF GAPS TO CAPABILITY CATEGORY I FROM THE 2008 PEER REVIEW

FINDING NO.	DESCRIPTION OF FINDING	APPLICABLE SRs	SR REQUIREMENT	CURRENT STATUS / COMMENT	IMPORTANCE TO APPLICATION
SC-B5-01	While the LS-PSA-003 notebook provides some selected comparison of RMIEP MELCOR results to more recent MAAP runs, there is no documented comparison of how the LSCS success criteria compare to those used for sister plants or other similar comparisons as required for this SR. However, the success criteria used for LSCS appear to be consistent with those of other similar BWRs.	SC-B5	CHECK the reasonableness and acceptability of the results of the thermal/hydraulic, structural, or other supporting engineering bases used to support the success criteria. Examples of methods to achieve this include: (a) comparison with results of the same analyses performed for similar plants, accounting for differences in unique plant features (b) comparison with results of similar analyses performed with other plant specific codes (c) check by other means appropriate to the particular analysis	Closed: The Success Criteria have been reviewed. Comparisons of the resulting success criteria were reviewed and compared with other similar plants using the MAAP computer code as a basis, with NUREG-1150 BWR/5 plant results, and with NEDO 24708A (GE report on core damage prevention success criteria). No anomalies are identified in the LSCS success criteria.	None

TABLE A-2

STATUS OF GAPS TO CAPABILITY CATEGORY I FROM THE 2014 SELF-ASSESSMENT REVIEW

GAP	DESCRIPTION OF FINDING	APPLICABLE SRs	CURRENT STATUS / COMMENT	IMPORTANCE TO APPLICATION
#1	The screening of flood locations is based on one or more of the criteria taken from the ASME Standard. This is documented in Sections 2.3 and Table B.3-1 of the IF Notebook. However, one of the screening criteria has a potential impact on the screening process; that is the use of individual CCDPs instead of the most limiting CCDP when calculating the CDF for a particular IE (see IFQU-A3).	IFSO-A3[1] IFQU-A3[2]	Open – It is noted that the Addendum B of the ASME/ANS Standard issued in 2013 (ASME/ANS-RA-Sb-2013) (not yet endorsed by the NRC) has modified these criteria to allow the screening of individual water sources or groups of sequences using a CDF criteria of 1E-8/Rx yr. This standard would rank the LSCS treatment as Category II.	Not significant: The overall impact of this finding is minimal and therefore would have an insignificant impact on this analysis.
#2	Failure data development using surveillance test data should fulfill the requirements of DA-C10, and should be documented appropriately. Review surveillance test procedures and identify all failure modes that are fully tested by the procedures. Include data for the failure modes that are fully tested. The results of unplanned demands on equipment should also be accounted for.	DA-C6[3] DA-C10[4]	Open – It is expected that the assumptions used to collect data from Maintenance Rule and MSPI data sources, yield acceptable data. Review of surveillance test procedures and identification of all failure modes that are fully tested will likely result in very few changes and likely negligible changes to failure probabilities.	Not significant: The overall impact of this finding would be minimal and therefore would have an insignificant impact on this analysis.
#3	SR requires Reviewed LS-PSA-012 which takes credit for EQ as a reasonable pedigree for spray on instrumentation. The documentation of this presumption of operability for instrumentation does not meet the standard for expert judgment. Additionally, there is no data or analysis to justify this position. This was the only case identified in which this SR was used.	IFSN-A7[5]	Open - This additional level of refinement would have minimal impact on the internal flooding analysis results.	Not significant: The overall impact would be minimal and therefore would have an insignificant impact on this analysis.

Notes to Table A-2:

(1) IFSO-A3 CC 1-3 Requirement - SCREEN OUT flood areas with none of the potential sources of flooding listed in IFSO-A1 and IFSO-A2.

(2) IFQU-A3 CC 1-2 Requirement – SCREEN OUT a flood area if the product of the sum of the frequencies of the flood scenarios for the area, and the bounding conditional core damage probability (CCDP) is less than 10^{-9} /reactor yr. The bounding CCDP is the highest of the CCDP values for the flood scnarios iin an area.

(3) DA-C6 CC1 Requirement – Estimates of demands based on tests and procedures. Employ and document the methodology used for determining the standby component number of demands to include plant specific: (a) surveillance tests, (b) maintenance acts, (c) surveillance tests or maintenance on other components, (d) operational demands. Operational demands from post maintenance testing should not be included.

(4) DA-C10 CC1 Requirement – When using surveillance test data, REVIEW the test procedure to determine whether a test should be credited for each possible failure mode. COUNT only completed tests or unplanned operational demands as success for component operations.

(5) IFSN-A7 CC 1-3 Requirements - In applying SR IFSN-A6 to determine susceptibility of SSCs to flood-induced failure mechanisms, TAKE CREDIT for the operability of SSCs identified in IFSN-A5 with respect to internal flood impacts only if supported by an appropriate combination of:

(a) Test or operational data

(b) Engineering analysis

(c) Expert judgment

A.2.5 External Events

Although EPRI report 1018243 [A.6] recommends a quantitative assessment of the contribution of external events (for example, fire and seismic) where a model of sufficient quality exists, it also recognizes that the external events assessment can be taken from existing, previously submitted and approved analyses or another alternate method of assessing an order of magnitude estimate for contribution of the external event to the impact of the changed interval. Based on this, currently available information for external events models was referenced, and a multiplier was applied to the internal events results based on the available external events information. This is further discussed in Section 5.7 of the risk assessment.

The current Fire PRA Model is considered adequate for risk insights, and other applications if limitations are understood and taken into account. The conservative nature of the Fire PRA modeling and the present status of Fire PRA development lead to these limitations (see section 5.7 for additional details). A Fire PRA peer review was performed in December, 2015 [A.12]. Table A-3 summarizes the Fire PRA Peer Review results. Table A-4 reviews and assesses the potential impact of the 19 SRs that were found to be not met at Capability Category 1 or higher. The peer review focused on compliance to the ASME/ANS standard [A.4]. Although not identified by the peer review team, there is believed to be conservatisms that can be addressed in future updates that will lead to an overall reduction in CDF contribution.

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

TABLE A-3

SUPPORTING REQUIREMENTS ASSESSMENT TOTALS AS A FUNCTION OF CAPABILITY CATEGORY

	LSCS ASSESSMENT		
CAPABILITY CATEGORY	# OF SRS	% OF TOTAL SRS	% OF ASSESSED SRS
Not Met (I, II, or III)	19	4.5%	6.3%
I	2	0.5%	0.7%
I/II	11	2.6%	3.6%
II	36	8.6%	11.8%
II/III	26	6.2%	8.6%
III	2	0.5%	0.7%
Met (All)	208	49.6%	68.4%
Not Reviewed	0	0.0%	N/A
Not Applicable	115	27.4%	N/A
TOTAL:	**419**	**100.0%**	**100.0%**

TABLE A-4

2014 FIRE PRA PEER REVIEW RESULTS ASME/ANS STANDARD REQUIREMENTS NOT MET AND ASSOCIATED FINDINGS

SR	SR DESCRIPTION	FINDING(S)	FINDING DESCRIPTION(S)	SIGNIFICANCE
SY-A24	DO NOT MODEL the repair of hardware faults, unless the probability of repair is justified through an adequate analysis or examination of data. (See DA-C15.)	3-4	Basis: Two recovery probabilities are developed for instrument air. One is from the internal events PRA and involves restoration of air after total system loss. The other recovery split fraction is for restoration of the in air after brazed fittings are fire failed. The probability of these split fractions is not substantiated for fire PRA.	Not significant, as the ILRT uses a bounding methodology. Note, 20+ hours is available for recovery. IA has many isolation points and it is expected restoration will be justified with additional analysis and documentation.
SY-B6	PERFORM engineering analyses to determine the need for support systems that are plant-specific and reflect the variability in the conditions present during the postulated accidents for which the system is required to function.	3-11	MSO 2I concerns spurious closure of the min flow valve on the RHR pump while the RHR pump receives a spurious or valid signal to start. The Task 2 report states that the RHR pump circuit has been modified to not permit spurious starts. Therefore this MSO cannot occur. This may suffice for spurious RHR pumps starts, but does not extend to valid pump starts or based on false instrumentation inputs. This MSO should be re-instated, with appropriate operator actions to curtail the pump operation after it is detected when the minimum flow valve is closed.	Not significant, as the ILRT uses a bounding methodology.
QU-C1	IDENTIFY cutsets with multiple HFEs that potentially impact significant accident sequences/ cutsets by requantifying the PRA model with HEP values set to values that are sufficiently high that the cutsets are not truncated. The final quantification of these post-initiator HFEs may be done at the cutset level or saved sequence level.	1-22, 1-23	F&O 1-22; An HRA dependency analysis has been performed for the CDF results. A similar analysis has not been performed for LERF. F&O 1-23; The top 100 combinations were selected for inclusion in the Dependency Analysis, based on the DI measurement in the HRA Calculator. All other dependent combinations were screened away. DI is a risk achievement worth measurement: HEPs in each combination are set to 1 to measure the increase in risk for that combination. Peer review team noted Risk reduction worth is	F&O 1-22; Negligible impact as ILRT 3b risk is a function of CDF. F&O 1-23; Screening using risk reduction worth, would likely cause an increased number of operator actions combinations to be kept. An increase in CDF is expected. Given the overall conservative treatment of Fire, and bounding ILRT analysis, FPRA results are acceptable.

TABLE A-4

2014 FIRE PRA PEER REVIEW RESULTS ASME/ANS STANDARD REQUIREMENTS NOT MET AND ASSOCIATED FINDINGS

SR	SR DESCRIPTION	FINDING(S)	FINDING DESCRIPTION(S)	SIGNIFICANCE
			the relevant importance measure when selecting HFE combinations to be addressed for dependency.	
PP-A1	INCLUDE within the global analysis boundary all fire areas, fire compartments, or locations within the licensee-controlled area where a fire could adversely affect any equipment or cable item to be credited in the Fire PRA plant response model including those locations of a sister unit that contain shared equipment credited in the Fire PRA.	4-1	The Global Analysis Boundary does not specifically include a PAU for the Yard. Table A-1 of the Plant Partitioning Notebook does not include a PAU defining the remainder of the Yard/exterior that contains FPRA equipment (i.e., duct banks, manholes, other equipment).	Not significant, as the ILRT uses a bounding methodology. Note, it is expected that adding PAU zones for duct banks, manholes and other equipment will have a very small impact to overall Fire CDF.
ES-A2	REVIEW power supply, interlock circuits, instrumentation and support system dependencies and IDENTIFY additional equipment whose fire-induced failure, including spurious actuation, could adversely affect any of the equipment identified per SR ES-A1.	1-9	Examples were provided where ES-A2 requirements were note met: For the loss of feedwater, supporting equipment for the feedwater pumps, condensate pumps, condensate booster pumps is placed on the FPRA equipment list. However, for instrumentation, one pressure sensor was identified for the loss of feedwater initiator, but no other instrumentation was identified, such level 8 sensors (which may be part of the feedwater pump logic, reactor low level sensors (which could impact the MSIVs and lead to MSIV closure), drywell pressure sensors (which could lead to a spurious LOCA signal and loss of feedwater), switchgear undervoltage sensors (which could isolate the offsite power supplies). For interlocks related to initiating events, one interlock was identified for the spurious ADS: ADS DIV I RELAY LOGIC SPURIOUSLY OPERATES, ADS DIV II RELAY LOGIC SPURIOUSLY OPERATES. No other interlocks were identified, such as MSIV closure signal,	Not significant, as the ILRT uses a bounding methodology.

TABLE A-4

2014 FIRE PRA PEER REVIEW RESULTS ASME/ANS STANDARD REQUIREMENTS NOT MET AND ASSOCIATED FINDINGS

SR	SR DESCRIPTION	FINDING(S)	FINDING DESCRIPTION(S)	SIGNIFICANCE
			LOCA signal (spurious), or spurious feedwater pump turbine trip. For support system dependencies, the peer review noted that power supplies and air / nitrogen dependencies are not listed for some components. For example: MSIV power / air / nitrogen dependencies for the TM initiator; for the TC initiator, the valves and their support dependencies are not listed for the turbine gland sealing system. The documentation does not provide evidence that a review for power supply, interlock circuits, instrumentation and support system dependencies was performed to identify additional equipment whose fire-induced failure, including spurious actuation, could adversely affect any of the equipment identified per SR ES-A1.	
ES-C2	IDENTIFY instrumentation associated with each operator action to be addressed, based on the following: a) fire-induced failure of any single instrument whereby one of the modes of failure to be considered is spurious operation of the instrument, and b) if the potential consequence of the instrumentation failure is different from the consequences of other selected equipment whose failure, including spurious operation, will be included in the Fire PRA plant response model.	1-1	The equipment selection does not address item (a) of supporting requirement ES-C2, which is to identify spurious operation of any single instrument that can impact the actions / HFEs addressed by the FPRA (i.e., the actions modeled by the FPRA). For part (b) of SR ES-C2, the equipment selection examined the potential for undesired operator actions arising from a single spurious indication solely as part of the operator interview. No systematic evaluation, such as by a procedure-by-procedure review was documented. The intent of this SR is to identify any single instruments that 'could' cause undesired actions. From the perspective of the peer review, the outcome of the interview process provided insubstantial basis for	Not significant, as the ILRT uses a bounding methodology.

TABLE A-4

2014 FIRE PRA PEER REVIEW RESULTS ASME/ANS STANDARD REQUIREMENTS NOT MET AND ASSOCIATED FINDINGS

SR	SR DESCRIPTION	FINDING(S)	FINDING DESCRIPTION(S)	SIGNIFICANCE
			the conclusion that no undesired actions could arise from the spurious operation of any single instrument.	
CS-A1	IDENTIFY cables whose fire-induced failure could adversely affect selected equipment and/or credited functions in the Fire PRA plant response model.	1-19, 6-9, 6-11, and 6-14	F&O 1-19: The peer review examined the cable selection package for offsite power loss switchyard breaker (OCB 4-6). The circuit evaluation package includes two pages of notes regarding interlock evaluations and the notes and assumptions associated with the interlocks. For example, a note is made that 'the interlock associated with trip and lockout of SAT 242. Cables that can cause relay to actuate are to be included with SAT 242'. The FPRA development team indicated that this impact for SAT 242 is addressed by the FPRA, but that no systematic review of the circuit evaluation package notes was performed. F&O 6-9; Cable selection relied heavily on the Fire Protection report. The credited operational modes in the FPR and the FPIE were not reviewed to ensure all the failure modes in the FPIE, and therefore, FPRA were adequately cable selected using the FPR as the main source of cable selection information. F&O 6-11; The cable selection work performed related to the cable data in the Fire Safe Shutdown report pre-dates NEI-00-01 guidance and was done to the standards at that time. No other information is currently available regarding the circuit analysis techniques used for the Fire Safe Shutdown Report. In general,	Not significant, as the ILRT uses a bounding methodology. Note, F&O resolutions could lead to both risk increase and risk reduction.

TABLE A-4

2014 FIRE PRA PEER REVIEW RESULTS ASME/ANS STANDARD REQUIREMENTS NOT MET AND ASSOCIATED FINDINGS

SR	SR DESCRIPTION	FINDING(S)	FINDING DESCRIPTION(S)	SIGNIFICANCE
			the MSO circuit analysis work was performed using NEI-00-01, Revision 2 or Revision 3 (depending upon the particular package).6-14; The CS for the LSCS FPRA is limited to some extent to the component level even for risk significant components. With this level of resolution, multiple failure modes of a particular component may appear in the fire scenario. This may artificially increase the risk of certain components by adding conservative cutsets.	
CS-A2	IDENTIFY those circuits whose fire-induced failure due to hot shorts (intra-cable and intercable), by themselves, would adversely affect selected equipment due to spurious operation and IDENTIFY the cables supporting any identified circuits where hot shorts impacting any one cable (including both intra-cable and inter-cable hot shorts) could lead to spurious operation of selected equipment.	6-11, 6-14, 6-9	See CS-A1 above.	See CS-A1 above.
CS-A3	IDENTIFY any additional cables required to support the proper operation of, or whose failure could adversely affect, credited equipment or functions due to power supply and support system equipment, and IDENTIFY the related equipment per the SRs for HLR-ES-A, HLR-ES-B, or HLR-ES-C, as applicable.	6-11, 6-14, 6-9	See CS-A1 above.	See CS-A1 above.
CS-A9	INCLUDE consideration of proper polarity hot shorts on ungrounded dc circuits; requiring up to and including two independent faults could result in adverse consequences.	1-20	For the cable selection performed for the MSO circuited analyses, exclusions for the number of hot shorts and DC polarity hot shorts were made in some circumstances. With respect to the FPRA component states whose cable selection relies on the Fire Protection Report, the methodology used for Fire Protection Report is currently	Not significant, as the ILRT uses a bounding methodology.

TABLE A-4

2014 FIRE PRA PEER REVIEW RESULTS ASME/ANS STANDARD REQUIREMENTS NOT MET AND ASSOCIATED FINDINGS

SR	SR DESCRIPTION	FINDING(S)	FINDING DESCRIPTION(S)	SIGNIFICANCE
			unknown. Therefore, some proper polarity hot shorts on ungrounded dc circuits; requiring up to and including two independent faults could result in adverse consequences may not be included.	
CS-A11	If assumed cable routing used in the Fire PRA, IDENTIFY the scope and extent, and PROVIDE a basis for the assumed cable routing.	6-12	The LSCS FPRA used assumed cable routing on a large number of FPRA BEs. Some of this assumed routing included risk significant systems such as DG0, RCIC, as well as spurious operations such as FW overfill which impact risk significant systems such as RCIC. This over mapping of failures for risk significant systems may artificially skew the risk significance of some modeled systems and overall FPRA risk distribution. Assumed cable routing of this extent introduces uncertainty into the FPRA results and also conservatism, as well as the potential for non-conservatism.	Not significant, as the ILRT uses a bounding methodology. Note, use of assumed routing versus detailed circuit analysis introduces potential conservatisms as well as non-conservatisms.
PRM-B2	VERIFY the peer review exceptions and deficiencies for the Internal Events PRA are dispositioned, and the disposition does not adversely affect the development of the Fire PRA plant response model.	5-1, 5-2	Included in the 19 FPIE F&Os identified in Table C-1 as 'Open' are several of particular interest to the FPRA, including: *Suggestion SY-A4-01 - URE LS2010-0032 *Suggestion DA-C6-01 - URE LS2010-0051 *Finding DA-C8-01 - URE LS2010-0052 *Suggestion IF-C3b-01 - URE LS2010-0061 * SRs were not met at CC II or better.	No impact. Note, the referenced SRs were assessed as having little or no impact to the FPIE.
PRM-B9	For any cases where new system models or split fractions are needed, or existing models or split fractions need to be modified to include fire-induced equipment failures, fire-specific operator actions, and/or spurious actuations, PERFORM the systems analysis portion of the	3-4, 3-11, 3-13	F&O 3-4; Recovery of instrument air after failure of soldered joints is recovered by an operator action. The HEP is developed as any proceduralized action without regard as to whether, for the given fire, and the desired IA load, a recovery action	3-4 and 3-13: Not significant, as the ILRT uses a bounding methodology. Note, IA recovery is credited for Class II decay heat removal scenarios. These are typically not classified as LERF events.

TABLE A-4

2014 FIRE PRA PEER REVIEW RESULTS ASME/ANS STANDARD REQUIREMENTS NOT MET AND ASSOCIATED FINDINGS

SR	SR DESCRIPTION	FINDING(S)	FINDING DESCRIPTION(S)	SIGNIFICANCE
	Fire PRA model in accordance with HLR-SY-A and HLR-SY-B and their SRs in Section 2 with the following clarifications, and DEVELOP a defined basis to support the claim of non-applicability of any of these requirements in Section 2: • All the SRs under HLR-SY-A and HLR-SY-B in Section 2 are to be addressed in the context of fire scenarios including effects on system operability/functionality accounting for fire damage to equipment and associated cabling.		is possible, due to location of fire and location of failure. F&O 3-11; MSO 2I concerns spurious closure of the min flow valve on the RHR pump while the RHR pump receives a spurious or valid signal to start. The Task 2 report states that the RHR pump circuit has been modified to not permit spurious starts. Therefore this MSO cannot occur. This may suffice for spurious RHR pumps starts, but does not extend to valid pump starts or based on false instrumentation inputs. This MSO should be re-instated, with appropriate operator actions to curtail the pump operation after it is detected the min flow valve is closed. F&O 3-13; A fault tree development was added to accommodate failure of instrument air piping due to melting of the solder on the pipes. The top gate is input into an AND gate - SA-TOTAL-LOSS, which includes component based losses of instrument air. The top gate SA-TOTAL-LOSS should be an OR gate to separate the loss of IN-AIR due to component damage and piping failure.	3-11; Not significant, as the ILRT uses a bounding methodology.
PRM-B11	MODEL all operator actions and operator influences in accordance with the HRA element of this standard.	3-6	Instrumentation required for operator cues is identified. If no instrumentation is available, the action is failed. Further, the modeling is such that if all instruments are available, the HEP is developed assuming degraded cues. However, there is no discussion to	Not significant, as the ILRT uses a bounding methodology.

TABLE A-4

2014 FIRE PRA PEER REVIEW RESULTS ASME/ANS STANDARD REQUIREMENTS NOT MET AND ASSOCIATED FINDINGS

SR	SR DESCRIPTION	FINDING(S)	FINDING DESCRIPTION(S)	SIGNIFICANCE
			substantiate that the nominal HEP case is actually the case for degraded cues. Additionally, for the cases for degraded cues, considerable credit appears to be taken for recovery of cognition errors, given a fire with degraded cues. The guidance is to have at least three HEP cases - a) full instruments, b) partial instruments, c) no instruments. The PRM assumes cases a) and b) are the same as case a). Case c) is modeled correctly according to the guidance.	
FSS-D7	In crediting fire detection and suppression systems, USE generic estimates of total system unavailability provided that : a) the credited system is installed and maintained in accordance with applicable codes and standards, and b) the credited system is in a fully operable state during plant operation.	4-17	There is no generic estimate or plant-specific value assigned to the non-suppression probability. The non-suppression values are only based on the NUREG/CR-6850 generic values for unreliability with no account for unavailability.	Not significant, as the ILRT uses a bounding methodology. Note: Compensatory actions are taken when systems are unavailable.
FSS-D8	INCLUDE an assessment of fire detection and suppression systems effectiveness in the context of each fire scenario analyzed.	4-18	The Fire Modeling Treatments Notebook and the Fire Modeling Workbook do not assess the time to detector activation for fire scenarios; instead a 1 minute assumed automatic detection time is used in the fire scenario development. Automatic detection is credited in scenarios involving lower HRRs without assessment of the detection actuation timing and effectiveness for the specific scenario and fire size.	Not significant, as the ILRT uses a bounding methodology.
FSS-F1	DETERMINE if any locations within the Fire PRA global analysis boundary meet both of the following two conditions: a) Exposed structural steel is present; b) A high-hazard fire source is present in that location, and c) If such locations are identified, SELECT one or more fire	2-8	As described in the Exposed Structural Steel Analysis Notebook the process employed does not consider the possibility of high-hazard fire sources, other than significant quantities of combustible fluids, such as flammable gases i.e., hydrogen.	Not significant, as the ILRT uses a bounding methodology. Combustible fluids, including hydrogen gases have been analyzed. Additional analysis likely not to be risk significant. May be

TABLE A-4

2014 FIRE PRA PEER REVIEW RESULTS ASME/ANS STANDARD REQUIREMENTS NOT MET AND ASSOCIATED FINDINGS

SR	SR DESCRIPTION	FINDING(S)	FINDING DESCRIPTION(S)	SIGNIFICANCE
	scenario(s) that could damage, including collapse, the exposed structural steel for each identified location.		Also this process does not consider the introduction of a transient ignition source such as welding or a battery test load.	documentation only.
FQ-C1	ADDRESS dependencies during the Fire PRA plant response model quantification in accordance with HLR-QU-C and its SRs in Section 2 and DEVELOP a defined basis to support the claim of non-applicability of any of the requirements under HLR-QU-C in Section 2.	1-22, 1-23	See QU-C1.	See QU-C1.
FQ-F2	Document any defined bases to support the claim of non-applicability of any of the referenced requirements in Section 2 beyond that already covered by the clarifications in this section.	1-25	The Summary and Quantification Notebook, LS-PSA-021.11, Rev 0 does not document the defined bases to support the claim of non-applicability of any of the referenced requirements. The peer review found the following to be not applicable: QU-C3 is not applicable. The linked event tree methodology was not used. All of the sequence logic including transfers are explicitly linked in the one top model logic used for quantification.QU-B10 is not applicable. Modules, subtrees, or split fractions are not used.QU-B5 is not applicable. Breaking the circular logic was not necessary for the FPRA development.	No impact. Documentation issue only.

A.2.6 Seismic CDF

A LSCS seismic CDF PRA model is not maintained. As noted in section 5.7.3 of the main body of the LSCS ILRT risk assessment, recent NRC work documented in Reference 27 of the main body provides seismic CDF information. The updated 2008 USGS Seismic Hazard Curves provide a weakest link CDF model. The most conservative (highest) CDF value provided in the reference document was used. The seismic CDF chosen is judged to be sufficient to support an order of magnitude LSCS ILRT external events risk impact assessment.

A.2.7 PRA Quality Summary

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

The 2015 Fire PRA Model results and the seismic CDF from the weakest link model using updated 2008 USGS Seismic Hazard Curves are judged to be adequate in performing a bounding “order of magnitude” assessment of ILRT impact.

A.3 IDENTIFICATION OF KEY ASSUMPTIONS

The methodology employed in this risk assessment followed the EPRI guidance as previously approved by the NRC. The analysis included the incorporation of several sensitivity studies and factored in the potential impacts from external events in a bounding fashion. None of the sensitivity studies or bounding analysis indicated any source of uncertainty or modeling assumption that would have resulted in exceeding the acceptance guidelines. The accepted process utilizes a bounding analysis approach, mostly driven by that CDF contribution which does not already lead to LERF. Therefor,

there are no key assumptions or sources of uncertainty identified for this application (i.e. those which would change the conclusions from the risk assessment results presented here).

A.4 SUMMARY

A PRA technical adequacy evaluation was performed consistent with the requirements of RG-1.200, Revision 2 [A.1]. This evaluation combined with the details of the results of this analysis demonstrates with reasonable assurance that the proposed extension to the ILRT interval for LSCS Unit 1 and Unit 2 to fifteen years satisfies the risk acceptance guidelines in RG 1.174 [A.5].

A.5 REFERENCES

[A.1] Regulatory Guide 1.200, *An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk Informed Activities*, Revision 2, March 2009.

[A.2] Boiling Water Reactors Owners' Group, *BWROG PSA Peer Review Certification Implementation Guidelines*, Revision 3, January 1997.

[A.3] American Society of Mechanical Engineers, *Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications*, ASME RA-S-2002, New York, New York, April 2002.

[A.4] ASME/American Nuclear Society, Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications, ASME/ANS RA-Sa-2009, March 2009.

[A.5] U.S. Nuclear Regulatory Commission, An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis, Regulatory Guide 1.174, Revision 2, May 2011.

[A.6] Electric Power Research Institute, Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals: Revision 2-A of 1009325, EPRI TR-1018243, October 2008.

[A.7] NEI 05-04, Process for Performing Follow-on PRA Peer Reviews Using the ASME PRA Standard, Nuclear Energy Institute, Rev. 1, Draft G, November 2007.

[A.8] Regulatory Guide 1.200, An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk Informed Activities, Revision 1, January, 2007.

[A.9] LaSalle Generating Station PRA Peer Review Report, BWROG Final Report, July 2008.

[A.10] LSCS Self-Assessment of the LSCS PRA Against the Combined ASME/ANS PRA Standard Requirements, LS-PSA-016 Rev. 3, November, 2015.

[A.11] LSCS PSA Peer Review Certification Report, BWR Owners' Group, February 2000.

[A.12] LSCS Fire PRA Peer Review Report, April, 2016.

Appendix B

BYPASS LEAK RATE TEST RISK ASSESSMENT

B BYPASS LEAK RATE TEST RISK ASSESSMENT

<u>Background</u>

In an amendment dated November 7, 2001, the NRC approved TS revisions to the scheduling of the drywell to suppression chamber bypass test and the suppression chamber to drywell vacuum breaker leakage testing. The amendments require the drywell to suppression chamber bypass test to be conducted on a 10-year frequency and the drywell to suppression chamber vacuum breaker leakage tests to be conducted on a 24-month frequency. The latest drywell to suppression chamber bypass tests for Unit 1 was conducted on February 25-26, 2008 and Unit 2 was conducted on February 7-8, 2009. These tests were done following the Integrated Leak Rate Tests. The current surveillance interval is controlled under the LSCS Surveillance Frequency Control Program (SFCP) [B.1] and is expected to be revised under the SFCP to once every 15 years should the LSCS ILRT LAR be approved.

The following steps are used to perform the analysis for the DWBT interval extension:

- Review the design basis
- Review historical test results
- Develop qualitative technical justification of change
- Perform deterministic calculations
- Perform risk assessment of interval change

B.1 LSCS MARK II PRESSURE SUPPRESSION CONTAINMENT DESIGN

The LSCS containment design is described in Section 6.2.1.1 of the UFSAR [B.5]. LSCS incorporates a Mark II containment with the drywell located over the suppression chamber and separated by a diaphragm slab. The drywell floor has been designed to withstand a downward acting differential pressure of 25 psig in combination with the normal operating loads and safe shutdown earthquake (SSE). The drywell floor has also been designed to accommodate an upward acting deck differential pressure of 5 psig, in order to account for the Wetwell pressure increase that could occur after a loss-of-coolant accident (LOCA).

The primary function of the suppression chamber is to provide a reservoir of water capable of condensing the steam flow from the drywell and collecting the noncondensable gases in the suppression chamber air space. The suppression chamber is a stainless steel-lined posttensioned concrete vessel in the shape of a cylinder, having an inside diameter of 86 feet 8 inches. The foundation mat serves as the base of the suppression chamber. The suppression chamber is designed for the same internal pressure as the drywell in combination with the thermal, seismic, and other forces.

The entire suppression chamber is lined with stainless steel. The drywell floor support columns are also provided with a stainless steel liner on the outside surface. Two 36-inch diameter openings are provided for access into the suppression chamber for inspection. Under normal plant operation, these access openings are kept sealed. They are opened only when the plant is shut down for refueling and/or maintenance. The access openings are located in the cylindrical walls of the chamber 14 feet 2 inches above the suppression pool water level. The access openings are closed using a bolted steel hatch cover. The hatch cover is designed with a double seal and test plenum to ensure leaktightness.

The suppression chamber vent system consists of 98 downcomer pipes open to the drywell and submerged 12 feet 4 inches below the low water level of the suppression pool, providing a flow path for uncondensed steam into the water. Each downcomer has a 23.5-inch internal diameter. The downcomers project 6 inches above the drywell floor to prevent flooding from a broken line. Each vent pipe opening is shielded by a 1-inch thick steel deflector plate to prevent overloading any single vent pipe by direct flow from a pipe break to that particular vent.

Vacuum relief valves are provided between the drywell and suppression chamber to prevent exceeding the drywell floor negative design pressure and backflooding of the suppression pool water into the drywell. In the absence of vacuum relief valves, drywell

flooding could occur following isolation of a blowdown in the drywell. Condensation of blowdown steam on the drywell walls and structures could result in a negative pressure differential between the drywell and suppression chamber.

The vacuum relief valves are designed to equalize the pressure between the drywell and wetwell air space regions so that the reverse pressure differential across the diaphragm floor will not exceed the design value of five pounds per square inch.

The vacuum relief valves (four assemblies) are outside the primary containment and form an extension of the primary containment boundary. The vacuum relief valves are mounted in special piping which connects the drywell and suppression chamber, and are evenly distributed around the suppression chamber air volume to prevent any possibility of localized pressure gradients from occurring due to geometry. In each vacuum breaker assembly, two local manual butterfly valves, one on each side of the vacuum breaker, are provided as system isolation valves should failure of the vacuum breaker occur.

In addition to the 98 downcomers, 13 main steam safety/relief valve (SRV) discharge lines penetrate the diaphragm slab and terminate at a pre-designed submergence within the pool.

During a loss of coolant accident (LOCA) inside containment, the containment design directs steam from the drywell to the suppression pool via the downcomers through the pool of water to limit the maximum containment pressure response to less than the design pressure of 45 psig. The effectiveness of the LSCS pressure suppression containment requires that the leak path from the drywell to the suppression chamber airspace be minimized. Steam that enters the suppression pool airspace through the leak paths will bypass the suppression pool water (remaining noncondensed) and can result in a rapid post-LOCA increase in containment pressure depending on the size of the bypass flow area.

The design value for leakage area is determined by analyzing a spectrum of LOCA break sizes. For each break size there is a limiting leakage area. In determining the limiting leakage area, credit is taken for the capability of operators to initiate drywell and suppression pool sprays after a period of time sufficient for them to realize that there is a significant bypass leakage flow. The effect of suppression pool bypass on containment pressure response is greatest with small breaks. The design value of 0.0300 ft² for LSCS represents the maximum leakage area that can be tolerated for that break size that is most limiting with respect to suppression pool bypass.

LSCS Tech Spec (TS) requirements conservatively specify a maximum allowable bypass area of 10% of the design value of 0.0300 ft². The TS limit (i.e., 0.0030 ft²) provides an additional factor of 10 safety margin above the conservatisms taken in the steam bypass analysis. The drywell-to-suppression chamber bypass test verifies that the actual bypass flow area is less than or equal to the TS limit.

B.2 HISTORICAL TEST RESULTS

A review of the past test history for the drywell-to-suppression chamber bypass leakage test has identified no failures. The following are the test results:

TABLE B-1

DWBT TEST RESULTS COMPARED TO TECH SPEC ALLOWABLE (SCFM)

UNIT 1 (SCFM)	% OF TS ALLOWABLE	UNIT 2 (SCFM)	% OF TS ALLOWABLE
2008 – 9.80	13.2%	2009 – 5.34	7.1%
2000 – 1.51	2.0%	1999 – 1.04	1.4%
1999 – 0.78	1.0%	1998 – 0.82	1.1%
1995 – 2.20	3.0%	1996 - 0.01	0.01%

Note to Table B-1:

Acceptance criteria based on 0.0030 sq. ft. flow path is approximately 75 scfm. Acceptance criteria scfm values have small variations for each test depending on suppression chamber temperature.

The history of test results indicates that the typical leakage is about one to two orders of magnitude below the acceptance criteria (which is set at an order of magnitude below

the design basis limit). This excellent history combined with the conservatism included in the allowable leakage rate helps to support the qualitative justification provided below, and also helps support the low likelihood of a large undetected bypass leakage in the risk assessment.

B.3 QUALITATIVE JUSTIFICATION FOR DWBT INTERVAL EXTENSION

Several potential bypass leakage pathways exist:

- Leakage through the diaphragm floor penetrations (e.g., SRV discharge line downcomers)
- Cracks in the diaphragm floor/liner plate
- Cracks in the downcomers in the suppression pool airspace region
- Valve seat leakage in the four sets of drywell-to-suppression chamber containment vacuum breakers

The most likely source of potential bypass leakage is the four sets of drywell-to-suppression chamber vacuum breakers. The drywell-to-suppression chamber bypass leak test is currently performed on a schedule consistent with the ILRT. However, a vacuum breaker leakage test is performed every 24 months. Individual and total drywell-to-suppression chamber vacuum relief valve bypass leakage is verified to be acceptable in accordance with TS SR 3.6.1.1.4 and SR 3.6.1.1.5 and the Surveillance Frequency Control Program (SFCP).

A functional test of each vacuum breaker is performed every 92 days in accordance with TS SR 3.6.1.6.2 and the Surveillance Frequency Control Program (SFCP). Verification that each vacuum breaker is closed is performed every 14 days in accordance with TS SR 3.1.1.6.1 and the SFCP.

The vacuum breaker leakage test and stringent acceptance criteria, combined with the historical negligible non-vacuum breaker leakage, and thorough periodic visual

inspection[1] provide an equivalent level of assurance as the DWBT that the drywell to suppression chamber bypass leakage can be detected and/or measured in a reasonable timeframe.

B.4 DETERMINISTIC CALCULATIONS

As part of the risk assessment of the DWBT interval extension, a set of deterministic thermal hydraulic analyses have been performed to identify the impact of increased drywell to suppression chamber leakage on the risk spectrum.

Table B-2 summarizes the results of the deterministic thermal hydraulic analyses using the LSCS specific plant model (i.e., MAAP model). The results in Tables B-2 focus on the response of containment pressurization to water and steam LOCA events as a function of the drywell to suppression chamber bypass leakage.

Tables B-2 display the following key results from this analysis and the impact of increased drywell to suppression chamber bypass leakage:

- Small, medium, large steam LOCA events as well as a small water break LOCA challenge the ultimate containment pressure (~140 psig) capability for a leakage size of 100x Tech Spec leakage. The steam events have the potential to result in core damage and a Large Early Release (LERF) event. The time to drywell failure ranges from 2.6 to 3.7 hours. The small water LOCA results in drywell failure at 14 hours with the potential for a late release.
- A steam or water LOCA event with a concurrent drywell bypass leakage of size 10x TS leakage does not result in overpressurization (less than design pressure (45 psig) and the ultimate containment pressure limit. Therefore, CDF associated with this leakage size is not affected because adequate vapor suppression is present.

[1] The Suppression Pool Floor and walls are inspected per ASME Section XI IWL requirements, (every 5 years). The Suppression Pool Ceiling Liner is visually inspected to ASME Section XI IWE requirements (once every Period), which is 3-1/3 years. The Vacuum Breaker piping and associated components is also visually inspected per IWE, once every Period. (Inspection frequency provided in email from P. Bussey, LSCS Programs Engineer to J. Steinmetz, Jensen Hughes Engineer on 6/17/2016).

- The vacuum breaker failure-to-close bypass cases (480x TS leakage) are run for information. As shown in the table, steam LOCAs are a greater challenge than water LOCAs.

However, it should be noted that there are simple crew actions that can successfully mitigate the containment pressurization observed in the LOCA cases:

- Use of drywell sprays
- Emergency depressurization

Both actions are called for by the LSCS Emergency Operating Procedure, LGA-003 Containment Control [B.2] and neither system is adversely impacted by the LOCA initiating events.

The time frame for the mitigation system actions to prevent containment overpressure is derived directly from the deterministic calculations and is greater than the "early" phase (i.e., 5 hrs). This time means that the TSC is operational and actions according to the EOPs will be taken with a high degree of certainty, comparable to the certainty applied to the initiation of RHR.

In conclusion, for medium and large water LOCAs, variations in the drywell to suppression chamber bypass leakage, from zero to many times Tech Spec leakage, do not impact the vapor suppression capability of the LSCS containment and therefore do not significantlyimpact the calculated CDF or radionuclide release frequency for these accident scenarios. For small water LOCAs, and small, medium and large steam LOCAs the results indicate that the containment pressure exceeds the design pressure (i.e., 45 psig) during the 24 hour mission time of the PRA (for the 100x allowable leakage case and for the stuck open vacuum breaker case), and also exceeds the ultimate containment pressure (i.e., 140 psig). For simplicity, an operator action to initiate containment sprays or perform an emergency depressurization is assumed to be required to prevent containment overpressure failure for a leakage of this magnitude. These conclusions regarding the impact of the potential for increased drywell to suppression chamber leakage are factored into the risk assessment.

TABLE B-2

CONTAINMENT PRESSURE RESPONSE FOR LOCA INITIATORS AS A FUNCTION OF DRYWELL TO WETWELL BYPASS LEAKAGE

	DRYWELL PRESSURE (PSIG)						TIME TO DRYWELL FAILURE AT 140 PSIG (HOURS)	
	INITIAL PEAK		AT 5 HRS		AT 24 HRS			
MAAP Case(1) (2)	STEAM	WATER	STEAM	WATER	STEAM	WATER	STEAM	WATER
SLOCA-0L	N/A	N/A	25.5	23.3	27.6	26.5	N/A	N/A
SLOCA-10L	N/A	N/A	28.7	26.5	37.4	35.6	N/A	N/A
SLOCA-100L	N/A	N/A	209	65.3	404	158	2.6	14.0
SLOCA-480L(3)	N/A	N/A	256	65.0	429	109	1.3	14.1
MLOCA-0L	22.1	N/A	25.7	24.0	27.4	26.5	N/A	N/A
MLOCA-10L	22.5	N/A	29.1	27.1	37.3	36.1	N/A	N/A
MLOCA-100L	N/A	N/A	193	44.1	396	94.6	2.9	N/A
MLOCA-480L(3)	N/A	N/A	252	44.8	428	94.8	1.0	N/A
LLOCA-0L	26.3	21.4	25.1	5.0	27.0	5.3	N/A	N/A
LLOCA-10L	26.6	21.5	28.4	5.1	36.9	5.4	N/A	N/A
LLOCA-100L	N/A	22.7	175	5.1	388	5.4	3.7	N/A
LLOCA-480L(3)	N/A	26.8	199	5.2	400	5.9	2.7	N/A

Notes to Table B-2:

(1) MAAP cases run with RHR in suppression pool cooling mode and no containment sprays actuated.

(2) Case IDs: 0L cases indicate no DW to SP bypass, 10L and 100 L run with 10x and 10x Tech Spec leakage from DW to WW respectively.

(3) LOCA with ECCS available and stuck open vacuum breaker (480x Tech Spec leakage from DW to WW).

B.5 RISK ASSESSMENT

The Drywell to Suppression Chamber leakage can lead to the following perturbations on risk metrics:

- The increase in leakage could result in an increase in the failure probability of the vapor suppression function and consequential failure of containment. This could lead to pool bypass and core damage.
- The bypass leakage would result in an increase in the radionuclides in the suppression chamber airspace following an RPV breach if drywell sprays were unavailable. This could result in increased radionuclide release for suppression chamber breach cases or suppression chamber (wetwell) vent cases with core damage and no drywell failure or other pool bypass mechanisms.

The following steps are used for the risk assessment:

1. Determine sequences that are impacted by changes in bypass area.
2. Calculate probability of large bypass area.
3. Calculate risk metrics for original bypass test interval.
4. Calculate risk metrics for 10 year bypass test interval.
5. Calculate risk metrics for 15 year bypass test interval.
6. Summarize the changes in the calculated risk metrics.

Step 1 - Determine Sequences Impacted by Changes in Bypass Area

As shown in the deterministic calculations, the only accident sequences that are impacted by the DWBT interval extension are those severe accidents induced by a loss of containment integrity due to overpressure failure. Additionally, it was shown that the only potential contributors to this situation are small water LOCAs and small, medium and large steam LOCAs that have sufficiently high bypass leakage to allow continual containment pressurization coupled with no mitigating actions. The small water LOCA scenarios represent a potential change in CDF, but not LERF because the late failures would result in radionuclide releases at >5 hours after a general emergency is

declared[(1)]. The small, medium and large steam LOCAs represent potential change in CDF and may lead to an early release as containment fails within 5 hours.

Loss of containment from over pressurization with adequate vessel inventory make-up prior to failure, has the potential to cause loss of inventory make-up upon containment failure leading to core damage. Inventory make-up failure modes associated with containment failure are the following:

- Catastrophic overpressure failure of the containment in the drywell body region may disrupt all injection lines of FW, CRD, LP ECCS, and HPCS (2CN--RUPT-DWBF--)
- The large uncontrolled failure of containment may cause HPCS to become steam bound if it is taking suction from the suppression pool (2SY--STEAMBOUND-)
- Large overpressure failure of the containment in the suppression pool below the water line causes a loss of inventory and loss of suppression pool suction for LP ECCS and HPCS (2CN--RUPT-WWWF--)

The PRA model credits HPCS for inventory injection post containment failure. The probability of HPCS failing given containment failure is 0.358.

On the other hand, however, it is acknowledged that some accident scenarios that are currently classified as early wetwell region failures have the potential to be re-categorized as LERF due to the presence of a large bypass area that would render the fission product scrubbing capabilities of the suppression pool ineffective in reducing the source term below LERF threshold values.

(The current LSCS PRA does not include the DW to WW bypass leakage term as a potential failure mode. Therefore, the current baseline risk metric calculations need to be adjusted to incorporate the probability that the bypass leakage is unacceptably high.)

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(1) Some LERF contribution from the change in CDF would come from a failure of operators to declare a General Emergency (GSEP) when entry conditions are met. The probability of this operator action failure is 5E-02 in the LSCS PRA model. This increase is LERF is considered negligible (<1E-10/yr).

Step 2 - Calculate Probability of Large Bypass Area

Industry and LSCS experience with the results of the DWBT has been quite good. However, for simplicity and for consistency with the ILRT analysis for LSCS, it will be assumed that the base case potential for a large drywell to suppression chamber bypass leak (100La) is the same as was utilized for the ILRT analysis (i.e. 0.0023).

Additionally, consistent with the EPRI Guidance [B.3], the change in the probability of a large undetected bypass increases by a factor of 3.33 for a ten-year interval and an extension to a 15 year interval can be estimated to lead to a factor increase of 5.0 in the non-detection probability of a leak.

Step 3 - Calculate the Risk for the 3 in 10 Year Bypass Leak Rate Test Interval

The LSCS base case did not include DW to WW bypass failure. Therefore the frequency of the Base Case model is adjusted to incorporate the severe accident frequency.

As described in Step 2, the probability of a "large" bypass given the original DWBT interval and excellent historical test experience is assumed to be 0.0023. Thus, the CDF to be added to the base model is:

ΔCDF = (Small Steam LOCA + Small Water LOCA + Medium Steam LOCA + Large Steam LOCA) $*$ Large Bypass Leak Probability $*$ DW Spray Failure Probability $*$ Emergency Depressurization Failure Probability $*$ HPCS Failure Probability Given Containment Fails

Where the applicable LOCA[1] initiating event frequency, DW spray failure probability, emergency depressurization human error failure probability and HPCS failure given

(1) LOCA frequency is the sum of %S2-ST Small Steam LOCA (3.56E-03/yr), %S2-WA Small Water LOCA (3.52E-03/yr), %S1-CS Medium LPCS LOCA Above Core (2.09E-05/yr), %S1-HP Medium HPCS LOCA Above Core (2.89E-05/yr), %S1-LP Medium LPCI LOCA Above Core (1.55E-04/yr), %S1-ST Other Medium LOCA Above Core (2.96E-04/yr), %A-CS LLOCA LPCS Above Core (3.02E-06/yr), %A-HP LLOCA HPCS Above Core (3.49E-06/yr), %A-LP LLOCA LPCS Above Core (1.41E-05/yr), and %A-ST Large LOCA above TAF (2.20E-05/yr). Total = 7.62E-03/yr.

containment fails failure probability values are taken from the current LSCS PRA model. Thus:

ΔCDF = LOCA $*$ 0.0023 $*$ 5.23E-02 $*$ 8.30E-04 $*$ 3.58E-01
ΔCDF = 7.62E-03/yr $*$ 0.0023 $*$ 5.23E-02 * 8.30E-04 $*$ 3.58E-01 = 2.72E-10/yr

ΔLERF = LOCA (steam only) $*$ 0.0023 $*$ 5.23E-02 $*$ 8.30E-04 $*$ 3.58E-01
ΔLERF = 4.10E-03/yr $*$ 0.0023 $*$ 5.23E-02 * 8.30E-04 $*$ 3.58E-01
= 1.47E-10/yr

Adjustments are made to EPRI Category 2 for the "new" LERF contribution from small, medium and large steam LOCAs leading to an early release as containment fails within 5 hours. Adjustments are made to EPRI Category 7 to address the remaining contribution (2.72E-10/yr – 1.47E-10/yr = 1.25E-10/yr) of this "new" contributor to core damage. However, as can be easily seen, the "new" contributors to CDF and LERF are negligible compared with the previously assessed base case, and will not have any measurable impact on the results.

<u>Change in LERF for existing sequences</u>

The potential change in LERF is limited to those accident scenarios that were previously classified as early wetwell region failures in Category 7. This contribution comes from Low-Early (L/E) and Medium-Early (M/E) contributions with non-wetwell containment failures removed.

ΔMedium-Early (M/E) = ($M/E_{Original}$ – Non-Wetwell $Failures_{Original}$) * Large Bypass Leak Probability

= (1.17E-07/yr. – 9.52E-09/yr) * 0.0023 = 2.48E-10/yr.

ΔLow-Early (L/E) = (L/EOriginal – Non-Wetwell $Failures_{Original}$) * Large Bypass Leak Probability

= (3.68E-07/yr. – 1.21E-07/yr) * 0.0023 = 5.69E-10/yr.

These L/E and M/E will be assumed to represent a change in LERF and the contributions will be removed from Category 7 contributions and moved to Category 2 (Isolation Bypass Failure).

$$\Delta\text{EPRI Class 2} = \Delta\text{Medium-Early (M/E)} + \Delta\text{Low-Early (M/E)}$$
$$= 2.48\text{E-10/yr} + 5.69\text{E-10/yr} = 8.17\text{E-10/yr}$$

For the purposes of this assessment, the changes to EPRI Classes 3a and 3b from the ILRT interval extension will be ignored so as to isolate the potential impact of the changes on the DWBT interval extension. With the population dose information derived for LSCS as shown in Table 5.2-2 of the ILRT portion of the LSCS submittal, with the initial EPRI Class 2, and 7 frequency information obtained from the detailed information that was used to support the development of that table, and with EPRI Class 1 assigned the remaining CDF from the total, the revised base case results showing the adjustments to Class 2, and 7 as described above are shown in Table B-6.

It is noted that the potential exists for impacts of increased drywell to suppression chamber bypass leakage on the likelihood that early containment failure occurs. For example, a SBO scenario (i.e., loss of all injection) with molten core debris allowed to transport to the suppression pool near the time of vessel failure with various bypass leakage rates was explored. Molten debris in contact with significant volumes of water shortly after vessel failure could maximize the amount of steam generation resulting in a deleterious impact of the bypass leakage.

The LSCS Mark II containment design incorporates a sunken pedestal directly below the RPV. The sunken pedestal is sufficient to contain all the molten core debris. This pedestal area would be expected to be dry unless containment sprays were operating. The pedestal floor has equipment drain plates that are estimated to fail by core interaction in approximately 20 minutes (described in RMIEP Vol. 2), resulting in a drywell to wetwell airspace pathway. This drain plate pathway failure would exceed the postulated DWBT drywell to wetwell leakage area and would render a pre-existing

drywell to wetwell leakage moot. As such, the risk assessment assumes that there is no increase in LERF from this potential accident scenario (i.e. LERF due to early containment failure from drywell bypass vapor suppression failure near the time of vessel failure) due to changing the DWBT interval.

TABLE B-3
QUANTITATIVE RESULTS AS A FUNCTION OF ORIGINAL DWBT INTERVAL FOR 3 IN 10 YEARS FREQUENCY

EPRI CLASS	DOSE (PERSON-REM WITHIN 50 MILES)	ORIGINAL DWBT INTERVAL ACCIDENT FREQUENCY (PER YEAR)	ORIGINAL DWBT INTERVAL POPULATION DOSE RATE (PERSON-REM/YEAR WITHIN 50 MILES)
1	4.34E+03	4.18E-07[2]	1.81E-03
2	5.29E+06	9.69E-10 + 1.47E-10 + 8.17E-10 = 1.93E-9	1.02E-03
3a	4.34E+04	-	-
3b	4.34E+05	-	-
4	N/A	N/A	N/A
5	N/A	N/A	N/A
6	N/A	N/A	N/A
7	1.44E+06	1.68E-06 + 1.25E-10 - 8.17E-10 = 1.68E-06	2.41
8	1.61E+07	8.20E-8	1.32
TOTALS	**CDF** **LERF (Class 2 + Class 8)** **CCFP[1]**	**2.18E-6** **8.39E-8** **80.85%**	**3.74**

Notes to Table B-3:

(1) Determined from (Class 2 + Class 7 + Class 8) / (Total CDF)

(2) Intact containment CDF w/o subtracting class 3a and 3b contributors.

Step 4 - Calculate the Risk for 10 Year Bypass Leak Rate Test Interval

The risk metrics for the 10 year DWBT interval are the same as the base case from Step 3, except the impact of the bypass leakage is increased by a factor of 3.33 consistent with the ILRT assessment. The revised results are shown in Table B-4.

TABLE B-4

QUANTITATIVE RESULTS AS A FUNCTION OF 10 YEAR DWBT INTERVAL

EPRI CLASS	DOSE (PERSON-REM WITHIN 50 MILES)	10 YEAR DWBT INTERVAL ACCIDENT FREQUENCY (PER YEAR)	POPULATION DOSE RATE (PERSON-REM/YEAR WITHIN 50 MILES)
1	4.34E+03	4.18E-07	1.81E-3
2	5.29E+06	9.69E-10+ 3.33 * 9.63E-10 = 4.18E-09	2.21E-2
3a	4.34E+04	-	-
3b	4.34E+05	-	-
4	N/A	N/A	N/A
5	N/A	N/A	N/A
6	N/A	N/A	N/A
7	1.44E+06	1.68E-06 + 3.33 * (1.25E-10 - 8.17E-10) = 1.68E-06	2.41
8	1.61E+07	8.20E-08	1.32
<u>**TOTALS**</u> **CDF** **LERF (Class 2 + Class 8)** **CCFP**		 **2.18E-6** **8.61E-8** **80.85%**	 **3.75**

Step 5 - Calculate the Risk for 15 Year Bypass Leak Rate Test Interval

The risk metrics for the 15 year DWBT interval are the same as the base case from Step 3, except the impact of the bypass leakage is increased by a factor of 5.0 consistent with the ILRT assessment. The revised results are shown in Table B-8.

TABLE B-5

QUANTITATIVE RESULTS AS A FUNCTION OF 15 YEAR DWBT INTERVAL

EPRI CLASS	DOSE (PERSON-REM WITHIN 50 MILES)	15 YEAR DWBT INTERVAL	
		ACCIDENT FREQUENCY (PER YEAR)	POPULATION DOSE RATE (PERSON-REM/YEAR WITHIN 50 MILES)
1	4.34E+03	4.18E-07	1.81E-3
2	5.29E+06	9.69E-10 + 5.0 * 9.64E-10 = 5.79E-09	3.06E-2
3a	4.34E+04	-	-
3b	4.34E+05	-	-
4	N/A	N/A	N/A
5	N/A	N/A	N/A
6	N/A	N/A	N/A
7	1.44E+06	1.68E-06 + 5.0 * (1.25E-10 - 8.17E-10) = 1.68E-06	2.41
8	1.61E+07	8.20E-08	1.32
TOTALS CDF LERF (Class 2 + Class 8) CCFP		**2.18E-6** **8.77E-8** **80.86%**	**3.76**

Step 6 - Summarize the Changes in the Calculated Risk Metrics

Consistent with the ILRT assessment, the relevant figures of merit are change in LERF, population dose, and conditional containment failure probability (CCFP). Additionally, the DWBT extension will also lead to a change in CDF as previously described. The results for these figures of merit from the DWBT interval extension are shown below in Table B-6.

Table B-6

SUMMARY OF QUANTITATIVE RESULTS FOR DWBT INTERVAL EXTENSION REQUEST

FIGURE OF MERIT	ORIGINAL DWBT INTERVAL	10 YEAR DWBT INTERVAL	15 YEAR DWBT INTERVAL
CDF (/yr)	2.180E-06	2.181E-06	2.181E-06
LERF (Class 2,8) (/yr)	8.39E-08	8.61E-08	8.77E-08
Dose (person-rem/yr)	3.74	3.75	3.76
CCFP (%)	80.85%	80.85%	80.86%
Changes from 3 in 10 yr. interval			
Increase in CDF (/yr)		**6.35E-10**	**1.09E-09**
Increase in LERF (/yr)		**2.25E-09**	**3.86E-09**
Increase in Dose (person-rem/yr)		**0.0096**	**0.016**
Increase in CCFP (%)		**0.01%**	**0.01%**

Based on the results of the deterministic studies and their probabilistic risk assessment implications, the following can be defined:

- Increasing the DWBT interval is assumed to increase the probability of increased bypass leakage.
- There is a change in core damage frequency (CDF) associated with the possibility that a small LOCA occurs with the increased DW to WW bypass leakage and the containment pressurization is not mitigated. This is conservatively assumed to lead to containment failure and consequential loss of RPV makeup and results in core damage.
- There is also a change in the large early release frequency (LERF) associated with the possibility that previous early WW region failures that were not considered LERF due to the fission product scrubbing effects of the suppression pool would be LERF if sufficient bypass leakage area exists.
- The change in population dose associated with the other changes above is noted in Table B-6. The overall change in population dose is negligible (<<1%).
- There is also a change in the conditional containment failure probability (CCFP) with an increase in CDF. It is also noted that the increase in LERF is only from cases that were already containment failure cases (albeit shifted to a LERF release).

The risk metric changes to be compared are then:

Δ CDF	= 1.09E-09/yr
Δ LERF	= 3.86E-09/yr
Δ Person-rem dose rate	= 0.016 person-rem/year
Δ CCFP	= 0.01%

The changes in CDF and LERF meet the Regulatory Guide 1.174 [B.4] acceptance guidelines for very small risk change. The change in population dose rate is well below the acceptance criteria of ≤1.0 person-rem/yr or <1.0% person-rem/yr defined in the EPRI guidance document [B.3]. Change in CCFP of 0.01% is approximately two orders of magnitude below the EPRI guidance document acceptance criteria of less than 1.5%.

The change in the risk metrics associated with the DWBT interval extension calculated above are based on internal events. The changes are small and would not significantly change even if the potential impact from external events as calculated in Section 5.7.5 of the main body were to be incorporated. In summary, the change in the DWBT interval extension from 3 in 10 years to 1 in 15 years is found to result in an acceptable change in risk.

B.6 REFERENCES

[B.1] LSCS SFCP-U2 Surveillance Frequency Control Program List Of Surveillance Frequencies, Rev 010.

[B.2] LSCS Emergency Operating Procedure LGA-003 Containment Control Revision 16.

[B.3] Electric Power Research Institute, Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals: Revision 2-A of 1009325, EPRI TR-1018243, October 2008.

[B.4] U.S. Nuclear Regulatory Commission, An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis, Regulatory Guide 1.174, Revision 2, May 2011. tory Guide

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

[B.5] Letter from David Gullot, Exelon Generation to US NRC, subject: LSCS Updated Final Safety Analysis Report (UFSAR) Rev. 21, July 31, 2015.