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10 CFR 50
10 CFR 51
10 CFR 54

RS-15-193

August 6, 2015

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

LaSalle County Station, Units 1 and 2
Facility Operating License Nos. NPF-11 and NPF-18
NRC Docket Nos. 50-373 and 50-374

Subject: Response to NRC Requests for Additional Information, Set 5, dated July 7, 2015 related to the LaSalle County Station, Units 1 and 2, License Renewal Application (TAC Nos. MF5347 and MF5346)

References:

1. Letter from Michael P. Gallagher, Exelon Generation Company LLC (Exelon), to NRC Document Control Desk, dated December 9, 2014, "Application for Renewed Operating Licenses"

2. Letter from Jeffrey S. Mitchell, US NRC to Michael P. Gallagher, Exelon, dated July 7, 2015, "Requests for Additional Information for the Review of the LaSalle County Station, Units 1 and 2 License Renewal Application – Set 5 (TAC Nos. MF5347 and MF5346)"

In Reference 1, Exelon Generation Company, LLC (Exelon) submitted the License Renewal Application (LRA) for the LaSalle County Station (LSCS), Units 1 and 2. In Reference 2, the NRC requested additional information to support staff review of the LRA.

Enclosure A contains the responses to this request for additional information.

Enclosure B contains updates to sections of the LRA (except for the License Renewal Commitment List) affected by the responses.

Enclosure C provides an update to the License Renewal Commitment List (LRA Appendix A, Section A.5). There are no other new or revised regulatory commitments contained in this letter.

If you have any questions, please contact Mr. John Hufnagel, Licensing Lead, LaSalle License Renewal Project, at 610-765-5829.

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

Executed on 08-06-2015

Respectfully,

Michael P. Gallagher

Michael P. Gallagher
Vice President - License Renewal Projects
Exelon Generation Company, LLC

Enclosures: A: Responses to Set 5 Requests for Additional Information
B: LSCS License Renewal Application Updates
C: LSCS License Renewal Commitment List Updates

cc: Regional Administrator – NRC Region III
NRC Project Manager (Safety Review), NRR-DLR
NRC Project Manager (Environmental Review), NRR-DLR
NRC Project Manager, NRR-DORL- LaSalle County Station
NRC Senior Resident Inspector, LaSalle County Station
Illinois Emergency Management Agency - Division of Nuclear Safety

Enclosure A

Responses to Requests for Additional Information related to various sections of the LaSalle County Station (LSCS) License Renewal Application (LRA)

RAI 3.3.1.110-1
RAI B.2.1.10-1
RAI B.2.1.13-1
RAI B.2.1.13-2
RAI B.2.1.13-3
RAI B.2.1.13-4
RAI B.2.1.18-1
RAI B.2.1.18-2
RAI B.2.1.23-1
RAI B.2.1.23-2
RAI 4.1-1
RAI 4.1-2
RAI 4.1-3

RAI 3.3.1.110-1

Background:

License Renewal Application (LRA) Table 3.3.1, Item 3.3.1-110 addresses cracking due to stress corrosion cracking (SCC) of stainless steel piping, piping components, and piping elements in the Auxiliary Systems, which are exposed to treated water greater than 60 °C (140 °F). The Generic Aging Lessons Learned (GALL) Report recommends GALL aging management program (AMP) XI.M7, "BWR Stress Corrosion Cracking," and GALL AMP XI.M2, "Water Chemistry," to manage this aging effect for the components. The GALL Report also indicates that GALL AMP XI.M7 is based on the staff positions described in Generic Letter (GL) 88-01.

LRA Table 3.3.1 indicates that Item 3.3.1-110 is not applicable because the Boiling Water Reactor (BWR) Stress Corrosion Cracking program manages crack initiation and growth in reactor coolant pressure boundary piping, welds and components greater than 4 nominal pipe size (4 NPS). The LRA also indicates that LRA Item 3.3.1-19, in comparison with Item 3.3.1-110, is used to manage cracking of stainless steel piping, piping components, and piping elements which are less than 4 NPS and exposed to treated water greater than 140 °F in the auxiliary systems.

The staff noted that the following reference with its Enclosure 1 indicates that the applicant's BWR Stress Corrosion program, which is based on GL 88-01, includes American Society of Mechanical Engineers (ASME) Code Class 1, 2, and 3 piping made of stainless steel that contains reactor coolant at temperature above 200 °F during power operation.

- Dresden Station Units 2 and 3; Quad Cities Stations Units 1 and 2; LaSalle County Station Units 1 and 2; Response to Generic Letter 88-01; Docket Nos. 50-237/249, 50-245/265, 50-373/374; July 29, 1988 (Agencywide Documents Access and Management System (ADAMS) Accession No. 8808090125)

Tables E-4 and E-5 in Enclosure 1 of the reference also indicate that the applicant's BWR Stress Corrosion Cracking program includes piping welds located in the Reactor Water Cleanup system. The staff further noted that LRA Section 3.3.1 indicates that the Reactor Water Cleanup system is included in the Auxiliary Systems.

Issue:

LRA Item 3.3.1-110 and Table 3.3.2-21 (the aging management review (AMR) table for the Reactor Water Cleanup System) do not identify the piping welds that are included in the applicant's program as described in the reference document above.

Request:

Clarify why LRA Item 3.3.1-110 and Table 3.3.2-21 do not identify the reactor water cleanup system piping welds that are included in the program as described in the reference document above. If these welds are within the scope of the program, add relevant AMR items to manage cracking due to SCC for these components.

Exelon Response:

The stainless steel portion of the plant Reactor Water Cleanup (RWCU) system that is included in the scope of the BWR Stress Corrosion Cracking (B.2.1.7) program is the ASME Code Class 1 portion of the system. This piping is identified as piping design class A949LS on license renewal boundary drawings LR-LAS-M-97, sheet 1 (Unit 1) and LR-LAS-M-143, sheet 1 (Unit 2) at drawing coordinate B-8. As discussed in LRA Sections 2.3.1.1 “Reactor Coolant Pressure Boundary System” and 2.3.3.21 “Reactor Water Cleanup System,” this portion of the Units 1 and 2 RWCU System is scoped with the Reactor Coolant Pressure Boundary (RCPB) System license renewal system. Therefore, the piping, piping components and piping elements are not identified in LRA Table 3.3.2-21 for the RWCU System, but instead are identified in LRA Table 3.1.2-1 for the RCPB System as pressure boundary/stainless steel/piping, piping components, and piping elements exposed to an internal environment of reactor coolant (Table 1 Item 3.1.1-97). Therefore, LRA Table 3.3.1 Item 3.3.1-110 does not apply to the RWCU license renewal system.

RAI B.2.1.10-1

Background:

GALL Report AMP XI.M17, "Flow-Accelerated Corrosion," as modified by LR-ISG-2012-01, "Wall Thinning Due to Erosion Mechanisms," states that the program relies on implementation of NSAC-202L, "Recommendations for an Effective Flow-Accelerated Program," Revision 2 or Revision 3. LRA Section B.2.1.10 states that the LaSalle County Station, Units 1 and 2 (LSCS) Flow-Accelerated Corrosion program is based on NSAC-202L, Revision 3. However, during the AMP Audit, it was disclosed that, after the submission of the LRA, the program was being revised to incorporate the guidance in NSAC-202L, Revision 4. The staff noted that NSAC-202L, Revision 4 was issued by the Electric Power Research Institute (EPRI) in November 2013, and this revision has not been previously considered in a license renewal safety evaluation.

Issue*:*

1. Since the applicant is using NSAC-202L, Revision 4, the LRA AMP is no longer consistent with the GALL Report AMP as originally stated in the LRA. Therefore, the applicant needs to demonstrate that the LRA AMP will ensure that the effects of aging in the impacted systems, structures and components will be adequately managed to prevent the loss of intended function.
2. For the trace chromium content exclusion, NSAC 202L, Revision 3 had previously included discussions about trace chromium content; however, the exclusion only applied after initial inspections confirmed that wear was not occurring. NSAC-202L, Revision 4 now incorporates an exclusion from evaluation for similar trace amounts of chromium without these initial inspections by stating, "Experience has shown…." EPRI report 1008047, "Flow-Accelerated Corrosion Investigations of Trace Chromium," was published in 2003, but it is not clear to the staff what bases support the experience aspect being cited in NSAC-202L, Revision 4 to justify the change.

Request:

1. As a result of LSCS's recent change to the implementation guidance for the Flow-Accelerated Corrosion program from that described in the LRA, if the LRA program will continue to be based on the GALL Report AMP, provide an explanation of the exception to the GALL Report AMP and the necessary program element changes to justify why the program, with exception, will be adequate to manage the effects of aging. Include a discussion of any technical changes that are incorporated in NSAC-202L, Revision 4, as they relate to each program element.
2. For the trace chromium system evaluation exclusion, provide information relating to the fleet or plant-specific experience that supports the basis for this change.

Exelon Response:

1. EPRI periodically revises NSAC-202L to update FAC program recommendations with the experience of members of the CHECWORKS™ Users Group (CHUG), and recent developments in detection, modeling, and mitigation technology. These recommendations refine and enhance those of earlier versions and ensure the continuity of existing FAC programs. The technical changes that affect the program elements of GALL Report AMP XI.M17 and the non-technical changes, as described below, represent improvements in the management of flow-accelerated corrosion. Therefore, this ensures that the main objective of the Flow-Accelerated Corrosion aging management program, which is to manage wall thinning, is maintained. The LSCS Flow-Accelerated Corrosion aging management program, as based on NSAC-202L-R4, will continue to manage the effects of aging so that the intended function(s) will be maintained consistent with the Current Licensing Basis (CLB) during the period of extended operation.

   Not every change between Revision 3 and Revision 4 of NSAC-202L will be discussed in this RAI response. The technical changes will be discussed as they relate to GALL Report AMP XI.M17 program elements. Non-technical changes, such as recommendations, will be identified. Editorial changes will not be discussed.

   Technical Changes:

   - GALL Report AMP XI.M17 Element 1 Scope of Program

     - NSAC-202L-R3 required the evaluation of components with measured chromium greater than 0.10%. It further stated that components with measured chromium greater than 0.10% and no significant wear during the first inspection need not be re-inspected. NSAC-202L-R4 excludes carbon steel material containing at least 0.10% chromium from evaluation. As a result, carbon steel material containing at least 0.10% chromium does not require inspection.

       This change is discussed in the response to item 2 below.

   - GALL Report AMP XI.M17 Element 4 Detection of Aging Effects

     - NSAC-202L-R4 revises the recommendations for selecting components for inspection. Entrance effect locations have been recommended as a consideration for selecting components for inspection. This effect occurs when flow passes from a FAC-resistant material to a nonresistant (susceptible) material, which causes a local increase in corrosion rate.

       The basis for this change is provided in EPRI Report 1015072, *Flow-Accelerated Corrosion – The Entrance Effect,* November 2007. This product is publicly available.

       It is noted that GALL Report AMP XI.M17 Element 7 Corrective Action, as revised by Final License Renewal Interim Staff Guidance LR-ISG-2012-01, addresses the issue of entrance effect. Element 7 recommends that when components are replaced with FAC-resistant materials, the susceptible

components immediately downstream should be monitored to identify any increase in wear due to the entrance effect as discussed in EPRI 1015072.

- GALL Report AMP XI.M17 Element 5 Monitoring and Trending

    - NSAC-202L-R4 paragraphs 4.3.1 “Calibrated Lines”, 4.3.1.2 “Special Consideration for Establishing Calibration” and 4.3.1.3 “Maintaining Calibration” are new.

        - Paragraph 4.3.1 was added to provide enhanced guidance for CHECWORKS modeled line calibrations to the program manager. It clarifies that the expectation is that the analyst will carefully evaluate each Analysis Line, determine whether it is considered calibrated or not, and document the results.

        - Paragraph 4.3.1.2 explains that there are a number of special situations where exceptions to the “General” criteria in 4.3.1.1 can be justified. Examples are provided where a modeled line which does not meet all of the “General” criteria might still be considered calibrated.

        - Paragraph 4.3.1.3 clarifies that once a line is considered calibrated, it is not necessary to re-calibrate the line each outage. However, the analyst must be aware of any plant operating or configuration changes which could impact calibration status. Direction is provided that in these instances, the calibration status of such lines should be reexamined and documented.

      It is noted that the information provided in NSAC-202L-R4 paragraph 4.3.1.1 “General Considerations for Establishing Calibration” is not new. This information was relocated from the definition of “Calibrated Analysis Line” in paragraph 4.1 of NSAC-202L-R3.

    - Three additional methods were added in NSAC-202L-R4 for determining the wear of piping components from UT inspection data. These are the Strip or Axial Method, Least Squares Slope Method, and Total Points Method.

      Information on these three methods has been previously provided to the NRC Division of License Renewal [ref. ML14309A700 and ML14309A702].

    - The hydrazine factor was removed from CHECWORKS™ since recent testing done at high temperatures has indicated that hydrazine concentration does not have an effect on FAC.

      The basis for this change is provided in EPRI Report 1008208, *Effect of Hydrazine on Flow Accelerated Corrosion,* March 2005. This product is publicly available.

- GALL Report AMP XI.M17 Element 6 Acceptance Criteria

- Added criterion which states that where the predicted or trended wall thickness is greater than the measured wall thickness a greater Safety Factor should be considered. A higher Safety Factor should be used in remaining service life calculations until the cause of the apparent higher measured vs. predicted wear is understood and/or mitigated to ensure adequate margin.

  It is noted that NSAC-202L-R4 did not change the recommendation that the minimum safety factor should never be less than 1.1.

Non-Technical Changes:

- Updated current industry status with respect to FAC. Added references for CHECWORKS™ Users Group and EPRI sponsored assessments.
- Added the recommendation that site program engineering supervision and management be trained in FAC.
- Added recommendations for record retention and record keeping when repairs or replacements are made.
- Added the recommendation to review the Susceptibility Analysis whenever significant plant changes are made.
- Added the recommendation to consider using acoustical monitoring to detect leakage past normally closed valves and malfunctioning steam traps.
- Added the recommendation to consider steam trap monitoring systems to determine trap performance.
- A new paragraph was added warning that adding the measured chromium to the CHECWORKS™ model may degrade the calculated line correction factor (LCF) and that analysts should be aware of this fact. This recommendation is the recognition of the fact that components with measured chromium will have less wall loss than carbon steel components without trace chromium. The use of low values of measured wear distorts the calculated LCF. This warning was added simply to alert analysts to this fact.
- The descriptions of the Band Method, Averaged Band Method, Area Method, Moving Blanket Method, and Point-to-Point Method for determining wear were deleted since these methods are described in the identified references.
- Clarified the guidance concerning the use of weld overlays. The service life of an overlay is to be determined by the licensee. Plants must ensure they are following their design requirements.
- Added a description of Online NobleChem™ Addition.
- Added recommendations for developing and maintaining a long term plan for large-bore as well as small-bore FAC for the life of the plant.
- Added a list of Position Papers published by the CHECWORKS™ Users Group.

2. NSAC-202L-R3 required the evaluation of components with measured chromium greater than 0.10%. It further stated that components with measured chromium greater than 0.10% and no significant wear during the first inspection need not be re-inspected. NSAC-202L-R4 excludes carbon steel material containing at least 0.10% chromium from evaluation. As a result, carbon steel material containing at least 0.10% chromium does not require inspection. There is significant evidence which supports the position that a chromium concentration greater than 0.10% provides protection against wall thinning due to flow-

accelerated corrosion. Laboratory results and more than 25 years of plant inspections support this position. Extensive documentation of studies performed exists as follows:

- Goyette, L.F. and Zysk, G.W., “Material Sampling in Erosion/Corrosion Programs,” PVP-Volume 259, ASME, 1993.
- Thailer, H., Dalal, K.J., Goyette, L.F., “Flow-Accelerated Corrosion in Steam Generators,” PVP-Vol. 316, Plant Systems. Component Aging Management, ASME, 1995.
- Chexal, B., Goyette, L. F., Horowitz, J. S., Ruščák, M., “Predicting the Impact of Chromium on Flow-Accelerated Corrosion,” PVP-Vol. 338, Pressure Vessels and Piping Codes and Standards, Volume 1, ASME, 1996.

These studies are further supported by the 2003 study done by EPRI to improve the accuracy of the chromium model used in CHECWORKS™. The bulk of this work involved analyzing plant data from six nuclear sites and developing revised chromium correlations. The research team gathered the most recent information available, which included data from the openly available literature, proprietary laboratory data made available by the Atomic Energy of Canada Ltd (AECL), and plant data from the members of the CHECWORKS™ Users Group.

Documentation of this study is provided in EPRI Report 1008047, *Flow-Accelerated Corrosion Investigations of Trace Chromium*, December 2003. This product is publically available.

LRA Appendix A, Section A.2.1.10 is revised as shown in Enclosure B to indicate that the Flow-Accelerated Corrosion program is based on EPRI guidelines in NSAC-202L-R4. LRA Appendix B, Section B.2.1.10 is revised as shown in Enclosure B to identify the GALL exception to the Flow-Accelerated Corrosion program and to provide justification for this exception.

LRA Tables 3.1.2-1, 3.2.2-1, 3.2.2-2, 3.2.2-3, 3.2.2-4, 3.3.2-21, 3.4.2-2, 3.4.2-3, 3.4.2-4, 3.4.2-5, 3.1.1 Item 3.1.1-60, 3.2.1 Items 3.2.1-11 and 3.2.1-65, 3.4.1 Items 3.4.1-5 and 3.4.1-60 are revised as shown in Enclosure B to identify the GALL exception to the Flow-Accelerated Corrosion program.

RAI B.2.1.13-1

Background:

LRA Section B.2.1.13, "Closed Treated Water System," states that the "Parameters Monitored or Inspected" and "Detection of Aging Effects" program elements will be enhanced by performing condition monitoring inspections on a representative sample of piping and components. While periodic inspections of a representative sample is consistent with the recommendations in GALL Report AMP XI.M21A, Standard Review Plan for License Renewal (SRP-LR) Section A.1.2.3.4 states that the basis for the sample size should be provided whenever sampling is used to represent a larger population of components.

Issue:

Documentation in the LRA and the onsite program basis documents did not include any details about the sample size. The staff could not verify that the size of the representative sample will be sufficient to ensure that the effects of aging would be adequately managed.

Request:

Provide details related to the size of the representative sample associated with the enhancement to the Closed Treated Water System program. As appropriate, include a discussion of the bases for the frequency of inspections to address cracking based on the operating experience discussed in RAI B.2.1.13-3.

Exelon Response:

For in-scope components, LaSalle Units 1 and 2 will perform periodic repetitive tasks which will inspect various component types that are in the "closed cycle cooling water" and "closed cycle cooling water > 140 °F" environments. Materials to be inspected include carbon steel, cast iron, copper alloy, and stainless steel. For the "closed cycle cooling water" environment, 25 inspections will be performed per unit, with at least two samples per unit of each material type. Since there are only a small number of stainless steel components in the "closed cycle cooling water > 140 °F" environment, 20 percent of the stainless steel components in this environment will be inspected per unit. The inspection locations are selected based on likelihood of loss of material, cracking, or fouling. The repetitive tasks will have a frequency interval not to exceed once every 10 years during the period of extended operation.

The 10 year frequency meets the recommendations in GALL Report AMP XI.M21A. The Closed Treated Water Systems aging management program includes strict chemistry controls in accordance with industry standard guidance to ensure successful mitigation of loss of material, cracking and fouling. Water chemistry parameters that are not within the range specified by procedures are identified and actions are taken to return all parameters within the specified goal range. Therefore, there is reasonable assurance that loss of material, cracking, and fouling will be successfully mitigated during the period of extended operation, and the ten-year inspection frequency will verify the mitigation of the aging effects during the period of extended operation.

As documented in Exelon's response to RAI B.2.1.13-3 (included in this letter) cracking of the reactor recirculation pump motor cooler tubing that occurred in 2004, was determined to originate from the external surface of the tubes, which is exposed to air and not cooling water,

and was not age-related but was rather determined to be associated with manufacturing and storage practices. In addition, operating experience indicates there have been no other plant specific events involving the aging effect of cracking in the closed cycle cooling water environments. However, as documented in Exelon’s response to RAI B.2.1.13-3, it was determined that the material of the cooler tubes is copper alloy with greater than 15% zinc, instead of copper alloy with less than 15% zinc shown in LRA Table 3.1.2-1. Cracking is an applicable aging effect for this material in a “closed cycle cooling water” environment. Therefore, the cracking aging effect is being added to LRA Table 3.1.2-1 as documented in Exelon’s response to RAI B.2.1.13-3. Accordingly, cracking of the recirculating pump motor cooler tubes, originating from internal surfaces, will be managed by the Closed Treated Water Systems aging management program and the recirculating pump motor coolers will be included in the periodic inspection sample population. Therefore, since operating experience indicates that cracking on internal surfaces in “closed cycle cooling water” and “closed cycle cooling water > 140 °F” environments has not occurred, a 10-year inspection frequency, which is consistent with the recommendations in GALL Report AMP XI.M21A, is considered adequate.

RAI B.2.1.13-2

Background:

LRA Section B.2.1.13 states that the Closed Treated Water System manages aging effects including the reduction of heat transfer. During its review of the LRA, the staff noted that the only components where this AMP manages reduction of heat transfer are the heat exchanger tubes in LRA Table 3.3.1-8, "Diesel Generator and Auxiliaries System." The staff also noted that the heat exchanger tubes for the drywell penetration cooling coils in LRA Table 3.3.2-1, "Closed Cycle Cooling Water System," are not being managed for reduction of heat transfer because the cooling provided to the drywell penetrations does not need to be credited for license renewal. In that regard, the staff noted that AMR item 3.5.1-3, associated with aging management of concrete exposed to elevated temperatures, is designated as "not applicable" because localized concrete temperatures greater than 200 °F have not been reported. The staff noted that, while cooling of the drywell penetrations may not be required to be credited, cooling of the drywell penetrations is the reason why localized concrete temperatures greater than 200 °F were not reported.

Issue:

SRP-LR Section A.1.2.1, "Applicable Aging Effects," states that an aging effect should be identified as applicable for license renewal even if there is a prevention program associated with that aging effect. It is unclear to the staff whether concrete temperatures adjacent to the drywell penetrations would be maintained less than 200 °F without cooling flow to the drywell penetration coils. Unless cooling flow to the drywell penetration coils is being periodically confirmed, it is unclear to the staff how the aging effects related to elevated temperatures in the concrete adjacent to the drywell penetrations can be considered as not applicable.

Request:

For the concrete adjacent to the drywell penetration cooling coils in LRA Table 3.3.2-1, "Closed Cycle Cooling Water System," either identify the activities that will be credited for ensuring that local temperatures will be maintained less than 200 °F, or provide the plant-specific AMP described in AMR item 3.5.1-3 for managing the reduction of strength and modulus due to elevated temperatures locally greater than 200 °F.

Exelon Response:

The drywell penetration cooling coils remove heat from the drywell penetrations for hot piping systems to prevent heat-induced degradation of the local concrete surrounding the penetrations during normal modes of reactor operation. The drywell penetration cooling coils are in-scope for 10 CFR 54.4(a)(2) leakage boundary because these cooling coils have potential spatial interaction with safety-related SSCs located within the Primary Containment. The cooling coils are nonsafety-related and do not perform a pressure boundary or heat transfer intended function for 10 CFR 54.4(a)(1), (a)(2), or (a)(3).

The cooling coils are serviced by the Reactor Building Closed Cooling Water (RBCCW) System. The RBCCW System is a nonsafety-related system and does not have a safety design basis. The RBCCW System is not necessary for a safe plant shutdown, or required during or after the design-basis loss-of-coolant accident.

The cooling coils cool the penetrations and prevent heat-induced degradation of the local concrete surrounding the penetrations during normal modes of reactor operation. This preventive measure is not a license renewal intended function. However, the Closed Treated Water Systems aging management program will be enhanced to provide assurance that this preventive measure is maintained during the Period of Extended Operation. The enhancement includes performing monitoring and trending of cooling coil outlet temperatures monthly to ensure that adequate cooling is being provided to the concrete adjacent to the drywell penetrations.

LRA Appendix A, Section A.2.1.13 and Appendix B, Section B.2.1.13 are revised as shown in Enclosure B.

LRA Appendix A, Section A.5 Commitment 13 is revised as shown in Enclosure C.

RAI B.2.1.13-3

Background:

LRA Section B.2.1.13 states that the aging effects being managed by the Closed Treated Water System program include cracking. During its review of the LRA, the staff noted that the only components for which this AMP manages cracking are the heat exchanger tubes and tube sheets in LRA Table 3.3.1-8, "Diesel Generator and Auxiliaries System." Plant-specific operating experience reports AR00299270, AR00200440, and AR00200182, identified cracking in the heat exchanger tubes associated with the reactor recirculation pump motor coolers; however, the staff noted that the heat exchanger tubes and tube side components for the reactor recirculation pump motor coolers in LRA Table 3.1.2-1, "Reactor Coolant Pressure Boundary System," are not being managed for cracking.

SRP-LR, Section A.1.2.1, "Applicable Aging Effects," states that the determination of applicable aging effects is based on degradation mechanisms that have occurred and those that potentially could cause structure or component degradation. Section A.1.2.1 also states that relevant aging information may be contained in plant-specific site deviation or issue reports.

Issue:

The applicable aging effects do not appear to be appropriately determined for the aging management of certain components being managed by this AMP, based on plant-specific operating experience reports.

Request:

Either provide the technical bases to show that cracking does not need to be managed in heat exchanger tubes and tube side components for the reactor recirculation pump motor coolers, or provide an additional AMR item that addresses this aging effect. Include a discussion to justify why this aging effect would not be applicable to other heat exchangers managed by this program for which cracking is not addressed.

Exelon Response:

The three operating experience reports cited above are related to a single event. AR 00200182 documented the discovery of cracking in the Unit 1 B reactor recirc motor cooler tubes during the refueling outage in 2004. The other ARs were generated to facilitate evaluation and repair of the as-found condition and to perform the extent of condition activities on the other reactor recirculation pump motor coolers.

A causal evaluation was performed, which included eddy current testing, inspection and analysis by industry experts. The cracking was determined to originate from the external surface of the tubes, which is exposed to air and not cooling water. The analysis concluded that this degradation was most likely caused by Transgranular Stress Corrosion Cracking (TGSCC) or Intergranular Stress Corrosion Cracking (IGSCC) due to high residual stresses and external contamination introduced through manufacturing practices or inadequate storage practices prior to installation. Corrective actions and extent of condition actions included performing

inspections and eddy current testing on all of the reactor recirculation pump motor coolers, and performing repairs as indicated by the eddy current results. Repair methods included the installation of full-length copper-nickel sleeves into the affected tubes or plugging the tubes.

Since the cause of degradation for the above event originated from the tube external surface (air side), and was determined to be associated with manufacturing and storage practices, and is therefore not age-related, cracking is not an applicable aging effect for this component and material combination in an indoor air environment.

During our review of this issue, it was determined that the material of the reactor recirculation pump motor cooler tubes is copper alloy with greater than 15% zinc, instead of copper alloy with less than 15% zinc as originally shown in LRA Table 3.1.2-1. Cracking is an applicable aging effect for copper alloy with greater than 15% zinc in a closed cycle cooling water environment. LRA Section 3.1.2.1.1, LRA Table 3.3.1 Item 3.3.1-72, and LRA Table 3.1.2-1 are revised as shown in Enclosure B to reflect this material change and to add the appropriate aging effects which include cracking and selective leaching. In addition, the material of the tube sleeves for the repaired tubes is included. As stated in the response to RAI B.2.1.13-1, the reactor recirculation pump motor coolers will be included in the periodic inspection sample population for the Closed Treated Water Systems program.

An extent of condition review was performed on components identified in the LRA as copper alloys with less than 15% zinc located in the following environments to confirm that the documented material is accurate: closed cycle cooling water, condensation, raw water, treated water, and waste water. An error was identified in the fire protection system for a subcomponent of the Tanks (Retard Chambers). Also, an additional material type was identified as being applicable for Valve Bodies in the Cardox subsystem. LRA Section 3.3.2.1.12 and LRA Table 3.3.2-12 are revised as shown in Enclosure B to correct these inconsistencies.

A discussion of the applicability of cracking to other heat exchangers managed by the Closed Treated Water Systems (B.2.1.13) program is as follows. Heat exchanger components that are monitored for cracking are those components that are constructed of copper alloys with > 15% zinc in water environments, and stainless steel components that are in a water environment with a temperature > 140 degrees F. Heat exchanger components that are not monitored for cracking are those components that are constructed of carbon steel, gray cast iron, and copper alloys with < 15% zinc. Stainless steel components in a low temperature water environment (i.e., temperatures < 140F) are also not monitored for cracking. This is consistent with GALL recommendations and industry operating experience documented in EPRI Technical Reports 1010639 (“Non-Class I Mechanical Implementation Guideline and Mechanical Tools”) and 1007821 (“Closed Cooling Water Chemistry Guideline”), and confirmed to be appropriate by reviews of plant-specific operating experience in which no occurrences of cracking was identified for these material and environment combinations. Therefore, the Closed Treated Water Systems (B.2.1.13) program monitoring for cracking in heat exchanger components is consistent with GALL recommendations, and industry and plant operating experience.

RAI B.2.1.13-4

Background:

Monticello's Licensee Event Report 263/2014-001, "Primary System Leakage Found in Recirculation Pump Upper Seal Heat Exchanger," documents intergranular stress corrosion cracking in a stainless steel heat exchanger tube caused by unrecognized localized boiling that led to an unexpected high concentration of chlorides from the chemistry constituents in the reactor building closed cooling water system. Exelon's evaluation of this operating experience report (Issue Report (IR) 1614784-02) identified differences between the heat exchanger configurations at Monticello (described as being internal to the pump and being a "tube within box") and LSCS (described as being external to the pump and being a "tube-within-tube"). The evaluation states that the coil configuration does not allow similar chlorides to concentrate on tubes and that because the heat exchanger is external to the pump, it is visually inspected every outage. The evaluation concludes that the heat exchanger design supports a much less challenging environment for the tubes.

Issue:

In its review of this evaluation, the staff could not conclude that the coil configuration at LSCS would prevent similar chloride concentrations because localized boiling could still occur in the tube-within-tube coil configuration. In addition, although the heat exchanger is external to the pump, visual inspections of the heat exchanger during outages cannot detect cracking of the interior tube, which is where the cracking would occur. Also, although the LSCS heat exchanger design may present a much less challenging environment for the tubes, without specific temperature information it cannot be determined whether localized boiling would occur, leading to a comparable, unexpected high concentration of chlorides. Based on temperature data provided to the staff during the audit, localized boiling within the heat exchanger did not appear to apply to LSCS. However, the evaluation of the industry operating experience documented in IR 1614784-02 did not provide sufficient bases to show that the coil configuration would prevent similar chloride concentration and that localized boiling would not occur.

Request:

For Licensee Event Report 263/2014-001, provide an assessment of the adequacy of the operating experience evaluation documented in IR 1614784-02 and any implications this has on the aging effects being managed by the Closed Treated Water System program.

Exelon Response:

The event described in Licensee Event Report (LER) 263/2014-001, referenced above, concerned boiling of reactor building closed cooling water (RBCCW), which led to accumulation of chlorides on the heat exchanger tube outer surface and provided the environment in which IGSCC can occur. The configuration of the recirculation pump seal cooler described in the LER is similar to the LSCS configuration in that both of the designs utilize a stainless steel heat exchanger tube with reactor recirculation pump seal water on the interior of the tube, being cooled by RBCCW on the exterior of the tube. However, there are several design differences

between the stations, which minimize the probability of this type of event from occurring at LSCS.

At Monticello, the recirculation pump seal water (the tube inner fluid) is reactor water, at reactor operating temperature and pressure. The seal cooler is located internal to the recirculation pump. At LSCS, the seal cooler is located external to the recirculation pump, where the ambient environment is much less challenging. By design, the recirculation pump seal water (the tube inner fluid) is not reactor water, but rather seal purge water from the control rod drive system, which is less than 140F during normal operation. Since the seal water temperature is below boiling, the RBCCW temperature will also remain below boiling. Therefore, chloride concentration due to localized boiling cannot occur, and the event that occurred at Monticello is not applicable to LSCS. However, operating data indicates that the stainless steel seal cooler tubes can be exposed to RBCCW temperatures greater than 140F. Cracking is an applicable aging effect for stainless steel components exposed to closed cycle cooling water at temperatures >140F, and is therefore applicable to the LSCS recirculation pump seal cooler.

As a result of our review of this issue, it was discovered that although the recirculation pump seal cooling function is described in LRA Sections 2.3.3.1 (Closed Cycle Cooling Water System) and 2.3.1.1 (Reactor Coolant Pressure Boundary System), the seal coolers were inadvertently omitted from LRA Tables 2.3.1-1, 3.1.2-1 and 3.3.1. These tables are revised as shown in Enclosure B to include the recirculation pump seal coolers. The recirculation pump seal coolers are a subcomponent to the recirculation pumps, and were not explicitly shown on the P&ID at the time of the scoping and screening phase of the license renewal project. Subsequently, a drawing change was processed to add them to the P&ID. An extent of condition review was performed on all design changes that were issued during the time period of LRA preparation and assembly, and no similar omissions were identified.

A discussion of the applicability of cracking to other heat exchangers managed by the Closed Treated Water Systems program is as follows. The Closed Treated Water Systems program includes monitoring for cracking in components which are stainless steel and exposed to water greater than 140F. This is consistent with GALL recommendations, and industry and plant operating experience. The operating experience documented in IR 1614784-02 occurred on a material and environment combination (stainless steel exposed to closed cycle cooling water at temperatures greater than 140F) in which cracking is managed by the Closed Treated Water Systems program.

LRA Section 3.1.2.1.1, Tables 2.3.1-1 and 3.1.2-1, and Table 3.3.1 Items 3.3.1-20, 3.3.1-44, and 3.3.1-49 are revised as shown in Enclosure B to add the recirculation pump seal coolers to the LRA and to include cracking as an applicable aging effect. Drawings LR-LAS-M-93-1 and 2, and LR-LAS-M-139-1 and 2 are also updated to include the recirculation pump seal coolers.

RAI B.2.1.18-1

Background:

GALL Report AMP XI.M29, “Aboveground Metallic Tanks,” as revised by LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation,” states that thickness measurements of tank bottoms are performed in accordance with Table 4a, “Tank Inspection Recommendations.” Table 4a provides guidance on the frequency of volumetric inspections performed on tank bottoms.

The Aboveground Metallic Tanks AMP has an enhancement (Enhancement No. 3) to perform volumetric inspections in accordance with LR-ISG-2012-02, Table 4a. During the onsite audit of the applicant’s Aboveground Metallic Tanks Program, the staff reviewed operating experience associated with the aging of tank bottoms. The bottoms of both cycled condensate storage tanks have experienced loss of material. The Unit 1 tank, 1CY01T, experienced leakage resulting from pitting in the tank bottom. Patches have been installed on the bottoms of both tanks to repair areas that were found to be below nominal thickness.

Issue:

The sufficiency of Enhancement No. 3 to effectively manage the tank bottoms for loss of material could not be determined during the AMP audit. It is unclear to the staff if the extent and locations of the volumetric inspections being performed are sufficient to manage loss of material during the period of extended operation.

Request:

Provide the extent of the volumetric inspections being performed and the methodology used to select the inspection location. The response should include details such as: (a) considerations being given to previous inspection results and patched locations, (b) percent of tank bottoms being inspected, and (c) grid spacing if discrete Ultrasonic Testing (UT) points are used for inspection. Justify the adequacy of the inspections being performed to manage the loss of material on the tank bottoms given the plant-specific operating experience.

Exelon Response:

LSCS performed UT inspections of 100% of accessible areas of the Cycle Condensate Storage Tank (CCST) bottoms in July 2010 for Unit 1 and June 2011 for Unit 2. Inspections were completed by draining the tanks and performing manual UT tank bottom thickness readings.

On the Unit 1 tank, there were 22 recorded findings (locations) with tank bottom losses resulting in tank bottom thickness below minimum allowable values; all were within 20 inches of the tank shell. For Unit 2, of the six recorded findings, four were found with tank bottom losses resulting in tank bottom thickness below minimum allowable values, all within four inches of the tank shell. Two additional locations were identified, with only minor tank bottom losses, within six feet of the tank shell.

All recorded findings have had “patch plates” installed. On Unit 1, two of these plates are exposed to the sand bed due to metallurgical samples being taken from the tank bottom prior to repair. On Unit 2, one of these plates is also exposed to the sand bed due to a tank bottom

sample being taken. These three patch plates are more susceptible to loss of material than the other patch plates because the bottom samples were removed exposing these three patch plates directly to the sand bed.

Since the overall health of the tank bottoms have been assessed by performing UT inspections of 100% of the accessible areas of the tank bottoms in 2010 and 2011, and the significant tank bottom loss has all been found within 20 inches of the tank shell, the subsequent (i.e., next) inspection scope will consist of 100% of the accessible areas of each of the tank bottoms within 30 inches of the shell. Included in this scope are the three patch plates that are directly exposed to the sand bed below. In addition, 10 random locations of approximately one square foot each, outside of the 30 inch band, will be inspected. This inspection program will encompass approximately 20% of the tank bottom and will inspect all the susceptible areas which were found during the baseline inspections. These inspections will use volumetric (i.e., eddy current) techniques with subsequent re-inspection of potential flaws identified, using discrete UT inspection technology. The inspections will not be performed using grid spacing with discrete UT points. Based on the results of this inspection, the scope will be reassessed for future tank bottom inspections, per the Corrective Action Program.

The existing enhancement (Enhancement 3) for volumetric inspection of the cycled condensate storage tanks is updated to include the extent of inspection that will take place during tank bottom inspections based on plant specific operating experience.

LRA Appendix A, Section A.2.1.18 and Appendix B, Section B.2.1.18 are revised as shown in Enclosure B to reflect this change to Enhancement 3. LRA Appendix A, Section A.5, Commitment 18 is revised as shown in Enclosure C to reflect this change to Enhancement 3.

RAI B.2.1.18-2

Background:

GALL Report AMP XI.M29, "Aboveground Metallic Tanks," as revised by LR-ISG-2012-02, states that caulk is applied to the interface of the tank bottom and foundation of outdoor tanks to mitigate the corrosion of tank bottoms. Table 3.0-1, "FSAR Supplement for Aging Management of Applicable Systems," of the SRP-LR, as revised by LR-ISG-2012-02, states that visual examinations are sufficient to monitor the degradation of caulking when supplemented with physical manipulation.

The Aboveground Metallic Tanks AMP has an enhancement (Enhancement No. 4) to perform visual inspections of the caulking at the interface of the tank bottom and foundation of the outdoor tanks for signs of degradation during each refueling interval.

Issue:

The sufficiency of Enhancement No. 4 to mitigate the corrosion of tank bottoms could not be determined during the AMP audit. The loss of material experienced by the tank bottoms has been partially attributed to chloride and moisture intrusion resulting from the failure of the flexible caulk seal at the interface of the tank bottom and foundation. It is unclear to the staff if visual inspections of the caulk, without being augmented with physical manipulation, are sufficient to manage the degradation of the caulk during the period of extended operation.

Request:

Provide and justify the technical basis used to determine that the visual inspection of the caulking at the interface of the tank bottom and foundation, without supplemental physical manipulation, is adequate to assess the degradation of the caulking.

Exelon Response:

The LSCS Aboveground Metallic Tanks program is an existing program that is enhanced to be consistent with NUREG-1801 aging management program XI.M29, as modified by LR-ISG-2012-02. The enhancement that requires visual examinations to monitor degradation of the caulking is revised to include physical manipulation.

LRA Appendix A, Section A.2.1.18 and Appendix B, Section B.2.1.18 are revised as shown in Enclosure B to reflect this change to the program description and Enhancement 4. LRA Appendix A, Section A.5, Commitment 18 is revised as shown in Enclosure C to reflect this change to Enhancement 4.

RAI B.2.1.23-1

Background:

GALL Report AMP XI.M35 states under the Detection of Aging Effects program element that "[t]his inspection should be performed at a sufficient number of locations to ensure an adequate sample. This number, or sample size, is based on susceptibility, inspectability, dose considerations, operating experience, and limiting locations of the total population of ASME Code Class 1 small-bore piping locations."

LRA Sections B.2.1.23 and A.2.1.23 do not provide the total number of in-scope small-bore piping welds.

Issue:

The LRA does not provide the weld populations. It is not clear to the staff how the inspection sample will be selected and thus whether a sufficient number of locations will be inspected to ensure that cracking will be adequately managed.

Request:

Provide the population of in-scope small-bore piping welds for each weld type (i.e., butt welds and socket welds) at each unit. Based on the population, justify the adequacy of the selected sample size for each type of weld.

Exelon Response:

The table below provides the total approximate population of ASME Section III Class 1 in-scope small-bore piping butt welds and socket welds equal to or greater than 1 inch NPS and less than 4 inch NPS for each LaSalle Unit. This table was developed by reviewing ISI program documents and drawings for small-bore piping at LaSalle.

	LaSalle Unit 1	LaSalle Unit 2
ASME Section III Class 1 Small-Bore Piping Socket Welds	483	458
ASME Section III Class 1 Small-Bore Piping Butt Welds	108	94

As documented in the response to RAI B.2.1.23-2, the one-time inspection sample size for LaSalle Unit 1 will include at least 3 percent of the population of program butt welds with a maximum of 10 program butt welds, and at least 3 percent of the population of program socket welds with a maximum of 10 program socket welds. These sample sizes are consistent with that recommended in GALL Report AMP XI.M35 for units that have extensive operating history (more than 30 years of operation) and have not experienced an age-related failure in ASME Code Class 1 small-bore piping.

LaSalle Unit 2 experienced one age-related failure of a Class 1 small-bore piping weld during its 31-year operating history as documented in the response to RAI B.2.1.23-2. Therefore, consistent with GALL Report AMP XI.M35, a plant-specific aging management program that includes periodic inspection is being implemented on Unit 2. Periodic inspections will be performed on those welds that are determined to be susceptible to the causal factors associated with the socket weld failure, which occurred in March 2005. Refer to the response to RAI B.2.1.23-2 for additional information related to this plant-specific program including the justification for the adequacy of the selected sample size for each type of weld.

LRA Sections A.2.1.23 and B.2.1.23 are revised to include or change the number of Unit 1 weld inspections and new LRA Sections A.2.2.2 and B.2.2.2 include the number of Unit 2 weld inspections that are required as a result of this response and the response to RAI B.2.1.23-2. These LRA changes are included in Enclosure B.

RAI B.2.1.23-2

Background:

GALL Report AMP XI.M35 states under the "Detection of Aging Effects" program element that the one-time inspection program does not apply to plants that have experienced cracking in ASME Code Class 1 small-bore piping due to stress corrosion, cyclical (including thermal, mechanical, and vibration fatigue) loading, or thermal stratification and thermal turbulence. LRA Section B.2.1.23 states that LSCS has not experienced this type of cracking. However, the LRA also states that the applicant's review identified two issues with ASME Code Class 1 small-bore piping welds during startup of LaSalle County Station, Unit 1, in 1983. The LRA further states that a pinhole leak was identified on a LaSalle County Station, Unit 2, ASME Code Class 1 small-bore socket weld in 2005. The LRA states that the pinhole leak was caused by an inclusion or defect in a repair weld performed in 1995.

Issue:

The staff reviewed the two issues identified for Unit 1 and noted that for both events, cracking was noted at a socket weld connection. Analyses of these events in 1983 revealed that the most likely cause of the event was an improper weld application or installation. However, the analyses did not yield a specific procedural non-compliance, but noted that the selected post weld heat treatment and filler metal selection was less than optimal. The analyses also noted that vibration may have contributed to crack propagation.

The staff also reviewed the leakage event identified for Unit 2, in 2005. The staff noted that the leakage occurred at the same location as the two cracking events identified for Unit 1 in 1983. The staff also noted that the 2005 event was attributed to a possible weld defect from a prior repair performed in 1995. It was assumed that a subsurface inclusion or porosity existed from the 1995 repair, which resulted in leakage in 2005.

Based on its review of the available information, the staff determined that the documented failures were very likely age-related, caused by vibration and/or thermal fatigue.

Request:

Provide information in terms of metallurgical analysis to support the determination that the multiple socket weld failures described above do not constitute failures of ASME Code Class 1 small-bore piping due to cyclical mechanical or thermal fatigue.

If the above failures of ASME Code Class 1 small-bore socket welds could be attributed to vibration or thermal fatigue, provide a plant-specific program that includes periodic inspections; otherwise, justify how the One-time Inspection of ASME Code Class 1 Small-Bore Piping program will adequately manage cracking consistent with the guidance provided in the GALL Report AMP.

Exelon Response:

The two Unit 1 socket weld failures identified in February 1983 were at the 2-inch drain connections to 26-inch main steam isolation valves (MSIVs), after less than nine months of intermittent plant operation. The causes were determined to be improper weld application and

installation, most likely related to less than optimum pre-heat treatment and welding electrodes. Corrective actions included a design change to re-weld the socket weld connections to all MSIVs on LSCS Units 1 and 2 using an improved welding procedure and instrumenting the Unit 1 drain lines to verify that no abnormal vibration amplitudes or frequencies existed. Since these failures occurred after less than nine months of intermittent plant operation, the failures in 1983 were not age-related. The corrective actions, including the design change, have been proven effective as indicated by more than 32 years of operation with no further indications of cracking or degradation on any Unit 1 ASME Class 1 small-bore piping. See revised LRA Section B.2.1.23, Operating Experience item 1 in Enclosure B for a discussion of this operating experience. Since there have been no ASME Class 1 small-bore piping failures due to age-related cracking caused by stress corrosion, vibration and/or thermal fatigue on Unit 1, the One-time Inspection of ASME Class 1 Small-Bore Piping AMP, consistent with GALL Report AMP XI.M35, is applicable for Unit 1.

A minor change is also being made to LRA Section A.2.1.23 to clarify that for socket welds, "if destructive examination is used, then each weld receiving a destructive examination can be credited as equivalent to having volumetrically examined two welds." This statement is consistent with the LRA Section B.2.1.23, Program Description and GALL Report AMP XI.M35.

It has been concluded that the Unit 2 socket weld failure in 2005 at the 2-inch main steam system drain connection to the 26-inch "D" outboard MSIV had causes that were related to aging mechanisms. Therefore, the One-time Inspection of ASME Class 1 Small-Bore Piping AMP, as described in GALL Report AMP XI.M35, is not applicable for Unit 2. A plant-specific program that includes periodic inspection will manage aging of Unit 2 ASME Class 1 small-bore piping.

Following is a summary of the events leading to the Unit 2 socket weld failure identified in 2005. In March 1995, a wall thickness measurement was performed in preparation for a freeze seal activity associated with a valve leak rate test. A minimum wall condition was identified on the 2-inch drain line that connects to the body of the "D" outboard MSIV. It was determined that the minimum wall condition had been caused by prior grinding on the external surface of the 2-inch line. The freeze seal was subsequently performed on the downstream line. After the freeze seal was completed, the piping segment consisting of the 2-inch line including the weld to the "D" outboard MSIV was replaced in April 1995. The new welds were examined via liquid penetrant. Therefore, the 1995 event did not involve degradation of any small-bore piping welds.

In March of 2005, during a VT-2 leakage test of the reactor coolant pressure boundary, leakage was identified at the socket weld where the 2-inch drain line connects to the body of "D" outboard MSIV. This is one of the welds that was replaced in 1995 as described above. The leakage was characterized as a steady stream from a pinhole (0.031 inch diameter) location in the weld. Destructive examination of the failed weld was not performed. The apparent cause of the failure was determined to be a weld inclusion or defect originating from the weld repair performed in April 1995. It was concluded that the pinhole flaw was due to porosity in the weld, and that the flaw likely developed below the surface. It is likely that operational stresses and/or mechanical stress risers due to the local curvature of the valve played a role in propagating the flaw.

Following is a summary of an evaluation performed in July 2015 on all Unit 2 plant systems that include ASME Code Class 1 small-bore piping to determine whether the age-related causes of

the socket weld failure identified in 2005 affect other systems. The drain line connected at the failed socket weld provides a continuous low flow of steam and condensate at maximum operating conditions of 1025 psig and 550 degrees F to the main condenser. The piping configuration at the failure was in the socket weld at the connection where the small-bore piping connects to the MSIV body. The MSIV serves as an equivalent anchor for the small-bore line, therefore any stresses in the drain piping due to vibration caused by flow in the steam line or drain lines can be expected to be highest at the socket weld connection to the valve. The causal factors that contributed to the weld failure include: a) a piping configuration where the small-bore piping is connected to a much larger component or pipe via a socket weld, and b) the small-bore line has flow during normal operation that can result in vibration and fatigue, with mechanical forces that are limiting at the socket weld connection to the larger component or pipe.

As discussed in GALL Report AMP XI.M35, "for systems that have experienced cracking and operating experience indicates that design changes have not been implemented to effectively mitigate cracking, periodic inspection is proposed, as managed by a plant-specific AMP." Additionally, GALL Report AMP XI.M35 states, "If small-bore piping in a particular plant system has experienced cracking, small-bore piping in all plant systems are evaluated to determine whether the cause for the cracking affects other systems (corrective action program)." The new Unit 2 plant-specific program reflects the results of the evaluation performed on all Unit 2 plant systems that include ASME Code Class 1 small-bore piping to determine whether the age-related causes of the socket weld failure identified in 2005 affect other systems. For those systems where the evaluation concluded that the age-related causes of the prior failure may affect additional welds, those susceptible Class 1 small-bore piping socket welds are included in a population that will be inspected periodically, including inspection prior to and during the period of extended operation, as described in new LRA Section B.2.2.2 within Enclosure B. This evaluation identified a population of 10 Unit 2 Class 1 small-bore piping socket welds that may be susceptible to the age-related causal factors associated with the Class 1 socket weld failure identified in 2005. Fifty percent of this population (i.e., five welds) will be inspected in the six year period prior to the period of extended operation and during each 10 year period during the period of extended operation.

The above described socket weld failure is the only instance of age-related failure of Unit 2 ASME Class 1 small-bore piping during the 31 year operating history. For those systems and welds where the evaluation concluded that the cause of the prior failure does not affect them, those welds will be included in a population that will be inspected via a one-time inspection prior to the period of extended operation, consistent with the guidance in GALL Report AMP XI.M35.

LRA Section 3.1.2.1.1, Tables 3.1.1 and 3.1.2-1; LRA Appendix A Table of Contents, Sections A.1.1, A.2.1.23; and LRA Appendix B, Table of Contents, Sections B.1.5, B.2.0, B.2.1.1, and B.2.1.23 are revised to describe the One-time Inspection of ASME Code Class 1 Small-Bore Piping AMP and clarify its applicability to Unit 1 only, as shown in Enclosure B. LRA Appendix A, Section A.5 Commitment 23 is revised to describe implementation of the Unit 1 One-time Inspection of ASME Code Class 1 Small-Bore Piping AMP on Unit 1 only, as shown in Enclosure C.

LRA Appendix A, Section A.2.2.2 and Appendix B, Section B.2.2.2 are added to describe the new plant-specific Unit 2 Inspection of ASME Code Class 1 Small-Bore Piping Program, as shown in Enclosure B. Also, LRA Section 3.1.2.1.1, Tables 3.1.1 and 3.1.2-1; LRA Appendix A Table of Contents and Section A.1.2; and Appendix B Table of Contents and Sections B.1.6,

B.2.0, and B.2.1.1 are revised to list the new plant-specific program. Appendix A, Section A.5, is revised to add Commitment 48 to include the commitment to implement the Unit 2 Inspection of ASME Code Class 1 Small-Bore Piping Program, as shown in Enclosure C.

RAI 4.1-1

Background:

In LRA Table 4.1-1, the applicant identifies that the current licensing basis (CLB) does not include any Time Limited Aging Analyses (TLAAs) associated with a flow-induced vibration limit for reactor vessel internal (RVI) components at LSCS.

Issue:

Updated Final Safety Analysis Report (UFSAR) Section 3.9.2.4 indicates that flow-induced vibrations of the RVI components were assessed as part of a pre-operational testing program and that the results of the program were summarized in General Electric (GE) Report No. NEDO-24057-P, "Assessment of Reactor Internals Vibration in BWR/4 and BWR/5 Plants," dated November, 1977. However, the staff noted that the UFSAR does not indicate whether the methodology in GE Report No. NEDO-24057-P included a time-dependent analysis for qualifying the structural integrity of the RVI components against the consequences of age-related effects caused by flow-induced vibrations.

Request:

Clarify whether the methodology in GE Report No. NEDO-24057-P included a time-dependent analysis, and if so, whether the analysis is relied upon to qualify the structural integrity of the RVI components against the consequences of aging effects caused by flow-induced vibrations. If the analysis is time-dependent, identify the aging effects and justify why the analysis would not need to be identified as a TLAA, when compared to the six criteria for qualifying analyses as TLAAs in 10 CFR 54.3(a).

Exelon Response:

NEDO-24057-P, *Assessment of Reactor Internals Vibration in BWR/4 and BWR/5 Plants,* is the proprietary version of a General Electric Licensing Topical Report that provides the analytical bases for the reactor internals vibration assessment program, including its acceptance criteria. It does not include a time-dependent analysis for qualifying the structural integrity of the reactor vessel internal components against the consequences of age-related effects caused by flow-induced vibrations. The vibration assessment program includes pre-test analysis for vibration predictions, vibration monitoring during flow testing, and the post-test inspection of reactor internals. There are no time-dependent vibration assumptions or requirements specified. Instead, a maximum limit on alternating stress amplitude is imposed as an acceptance criterion for the vibration testing that was to be performed on each reactor type.

Since there is no time-dependent analysis within NEDO-24057-P, it does not meet TLAA definition criterion (3) of 10 CFR 54.3(a), which is: "those licensee calculations and analyses that…(3) involve time-limited assumptions defined by the current operating term, for example, 40 years."

RAI 4.1-2

Background:

In the staff's safety evaluation (SE) on EPRI BWRVIP Technical Report (TR) No. BWRVIP-26-A dated December 7, 2000 (ADAMS Accession No. ML003776110), the staff issued Applicant Action Item (AAI) No. 4, requesting the BWR applicant's identification of any plant-specific TLAAs that may be applicable to the evaluation of BWR top guide components. In its response to this AAI, as provided in Appendix C of the LRA, the applicant states that the RAMA code fluence evaluation for the RVI components determined that the neutron fluence threshold for irradiation-assisted stress corrosion cracking (IASCC) susceptibility of the top guides has been exceeded. The applicant states that the fluence for RVI components is evaluated as a TLAA in LRA Section 4.2.1. The applicant states that no other TLAA has been identified to manage the effects of aging for the top guides and their components and that, during the period of extended operation, the aging of the top guide will be managed by inspections that are conducted as part of the BWR Vessel Internals program (LRA Section B.2.1.9).

Issue:

The applicant's response to AAI No. 4 on the BWRVIP-26-A report does not specifically state or address whether the CLB included any analysis of irradiation-induced or irradiation-assisted stress corrosion cracking in the top guide assemblies (or the subcomponents in the top guide assemblies) that would need to be identified as a TLAA for the LRA. The staff seeks additional clarification.

Request:

Clarify whether the current licensing or design basis includes an analysis or evaluation of irradiation-induced or irradiation-assisted SCC in LaSalle's top guide assemblies or components. If so, justify why the analysis would need to be identified as a TLAA when compared to the six criteria for qualifying analyses as TLAAs in Title 10 of the *Code of Federal Regulations* (10 CFR), Section 54.3(a).

Exelon Response:

Since the Applicant Action Item for BWRVIP-26-A identified Top Guide IASCC as a potential TLAA area, specific searches of CLB records were previously performed to identify any plant-specific TLAA associated with irradiation-induced or irradiation-assisted stress corrosion cracking of the Top Guide. None were identified.

A review of BWRVIP documents was also performed to determine if a generic TLAA was developed in support of these documents. The only analysis of Top Guide IASCC found was in BWRVIP-183, *Top Guide Grid Beam Inspection and Flaw Evaluation Guidelines*, Appendix A, *Top Guide Grid Beam Flaw Evaluation*. This appendix describes a grid beam flaw evaluation of a top guide in a BWR-5 plant from another site. A fracture mechanics evaluation of the flaw indications reported in the top guide grid beams for that plant was performed with consideration of fluence effects, including IASCC. The acceptability is documented for each of the indications due to various load combinations for continued operation for 10 years from the examination performed in 2005. However, since that evaluation only determined the crack growth that would

occur during a 10-year inspection interval at the BWR-5 plant from the other site, this analysis is not a TLAA because it does not meet TLAA criterion (3) of 10CFR 54.3(a), which is: “those licensee calculations and analyses that…(3) involve time-limited assumptions defined by the current operating term, for example, 40 years.” No other evaluation of irradiation-induced or irradiation-assisted stress corrosion cracking for top guide components was found.

Therefore, since the analysis in Appendix A of BWRVIP-183 does not meet the definition of a TLAA and since no other potential TLAAs were identified, there is no time-limited aging analysis of irradiation-induced or irradiation-assisted stress corrosion cracking for the RVI top guide assemblies (or the subcomponents in the top guide assemblies) within the LSCS CLB.

RAI 4.1-3

Background:

In LRA Section 4.1.2, the applicant states that it reviewed those exemptions previously granted in accordance with the requirements in 10 CFR 50.12 that apply to LSCS. The applicant states that none of the exemptions were associated with or supported by TLAAs. Therefore, the applicant stated that no further evaluation of these exemptions is required by the regulation in 10 CFR 54.21(c)(2).

Issue:

1. The operating licenses for LSCS identify that the applicant was granted specific exemptions from the requirements in 10 CFR Part 50, Appendix G, which is the rule that applies to the performance of mandated time-dependent pressure-temperature limit (P-T limit) and upper shelf energy (USE) analyses. The applicant was granted specific exemptions from meeting the requirements for certain types of containment leak rate testing activities under 10 CFR Part 50, Appendix J. However, neither the LRA nor the operating licenses specify what these exemptions involved. Therefore, the staff does not currently have sufficient information to make a determination as to whether these exemptions (as granted under 10 CFR 50.12) were based on a TLAA.

2. By letter dated November 8, 2000 (ADAMS Accession No. ML003771016), the staff granted specific exemptions in accordance with 10 CFR 50.12 to use analytical methods in ASME Code Cases N-640 and N-588 for P-T limit calculations of LSCS. In previous submittals, Exelon identified that these types of exemptions met the requirements in 10 CFR 54.21(c)(2). However, Exelon has not identified that the identical exemptions for LSCS meet the criteria in 10 CFR 54.21(c)(2).

Request:

1. Provide your basis why the exemptions listed in the operating licenses from 10 CFR Part 50, Appendix G, or 10 CFR Part 50, Appendix J, requirements are not considered as exemptions remaining in effect that were granted in accordance with 10 CFR 50.12 based on a TLAA. If it is determined that these exemptions were previously granted in accordance with 10 CFR 50.12, the exemptions remain in effect for the CLB, and they are based on a TLAA, provide your basis for not amending your LRA and submit an evaluation of the exemptions in accordance with the requirements in 10CFR 54.21(c)(2).

2. Justify why exemptions to use ASME Codes N-640 and N-588 at LSCS have not been identified as exemptions granted in accordance with 10 CFR 50.12 and are based on a TLAA.

Exelon Response:

1. The exemptions listed in the operating licenses from 10 CFR Part 50, Appendix G, 10 CFR Part 50, Appendix H, or 10 CFR Part 50, Appendix J requirements are not based on a TLAA because these exemptions are based on analyses that do not involve time-limited assumptions defined by the current operating term. Therefore, these exemptions are not required to be listed in the LRA.

   Below is a summary of these exemptions that describes why they are not based on a TLAA.

   Operating License Section 2D Appendix J Type A Exemption

   Section 2D(e) of the Unit 1 operating license and Section 2D(c) of the Unit 2 operating license 2 refer to an exemption granted pursuant to 10 CFR 50.12 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 shut down for the 10-year plant inservice inspections. This exemption addresses schedule requirements and is based on the results of previous testing results and not on any analysis. Therefore, this exemption is not based on a TLAA and is not listed in the LRA.

   Operating License Section 2D Appendix J MSIV Leakage Exemption

   Section 2D(f) of the Unit 1 operating license and Section 2D(e) of the Unit 2 operating license refer to an exemption granted pursuant to 10 CFR 50.12 to the requirements of 10 CFR 50, Appendix J that permits removal of the leakage rate from Main Steam Isolation Valves (MSIVs) from the acceptance criteria for the combined local leak rate tests (Type B and C), as defined in the regulations of 10 CFR Part 50, Appendix J, Option B, Paragraph III.B. The exemption allowed: (1) leakage testing of the MSIVs using a minimum test pressure of 20.2 psig applied between the MSIVs and a Technical Specifications leakage rate limit of 100 scfh per main steamline past the MSIVs, not to exceed a total of 400 scfh for all four main steamlines; and (2) exclusion of the measured MSIV leakage rate from the evaluation of the combined local leak rate tests. Another consideration in the granting of this exemption was the elimination of the Leakage Control System and the use of an alternate leakage treatment pathway for leakage past the MSIVs. Offsite dose calculations were performed in support of this exemption. The offsite dose calculations are associated with an emergency event, are not defined by the current operating term of 40 years, and do not meet the definition of a TLAA. Therefore, this exemption was determined to not be based on a TLAA and is not listed in the LRA.

   Operating License Section 2D Appendices G, H, and J Exemptions

   Section 2D(a) of the Unit 1 operating license and Section 2D(a) of the Unit 2 operating license refer to exemptions from certain requirements of Appendices G, H, and J that are described in the Safety Evaluation Report (SER) and supplements and provide detailed descriptions of each of these exemptions. These exemptions were reviewed to determine if any of them meet the criteria specified in 10 CFR 54.21(c)(2) that would require them to be listed in the LRA.

These exemptions to ASME Code Appendix G and Appendix H that were approved during initial licensing of LaSalle Units 1 and 2 were needed since the reactor vessels were designed and fabricated in accordance with the 1968 Edition of the ASME Code, but the NRC determined that, “based upon the reactor vessels order dates, and the construction permit date, this Section of the Code of Federal Regulations requires that the LaSalle reactor vessels meet the requirements of at least the 1971 Edition, including Addenda through Summer 1971.”

LaSalle requested relief in Amendment no. 11 to the Preliminary Safety Analysis Report dated January 14, 1974, from the Code Edition and Addenda, stating that it was impractical to update the design and fabrication requirements without imposing undue hardship without a compensating increase in quality and safety. The NRC reviewed and evaluated this noncompliance from the requirements of 10 CFR 50.55a and concluded that only minor differences exist in the design and fabrication requirements and that updating of the LaSalle design to meet the 1971 Edition, including the Summer 1971 Addenda, would not significantly increase the level of quality or safety, and that the present design requirements for the LaSalle Unit 1 and Unit 2 reactor vessels provide an acceptable level of quality and safety. Based upon the NRC evaluation, an exemption was granted to the requirements of Paragraph 50.55a(c)(2) for designing and fabricating the LaSalle reactor vessels to the ASME Boiler and Pressure Vessel Code 1971 Edition, including Summer 1971 Addenda.

Since the Edition and Addenda of the ASME Code used in the design and fabrication of the vessel preceded the publication date of Appendices G and H, some of the fracture toughness tests were not conducted to demonstrate explicit compliance with the then current requirements of Appendices G and H. The staff concluded from their review of the information submitted for LaSalle Unit 1 and Unit 2 that exemptions to some of the specific requirements of Appendices G and H of 10 CFR Part 50 were required.

An exemption from Appendix J described in the SER and supplements involved the acceptance of leak testing the main steam isolation valves at a reduced pressure and exclusion of the measured leakage from the combined leak rate for the local leak rate tests. This exemption was changed when current exemptions (2D(f) for Unit 1 and 2D(e) for Unit 2) were granted.

The review of these exemptions associated with the initial licensing of LaSalle Unit 1 and Unit 2 determined that they were previously granted in accordance with 10 CFR 50.12, and remain in effect for the CLB, but are not based upon a TLAA, and therefore, are not listed in the LRA.

2. During development of the LRA, searches were performed of docketed correspondence, the operating license, the Updated Final Safety Analysis Report (UFSAR), and Safety Evaluation Report to identify any exemptions that are required to be listed in the LRA by 10 CFR 54.21(c)(2), which states: “A list must be provided of plant-specific exemptions granted pursuant to 10 CFR 50.12 and in effect that are based on time-limited aging analyses as defined in § 54.3. The applicant shall provide an evaluation that justifies the continuation of these exemptions for the period of extended operation.”

LRA Section 4.1.5 states: “Exemptions currently in effect for LaSalle Unit 1 and Unit 2 pursuant to 10 CFR 50.12 were reviewed and it was determined that none were associated with or supported by TLAAs. Therefore, no further evaluation is required.”

Upon further review, there is one exemption to 10 CFR 50 Appendix G that was identified for LaSalle Unit 1 and Unit 2 that was determined to be based upon a TLAA and needed to be listed in LRA Section 4.1.5. This exemption was granted by letter dated November 8, 2000, that permitted the use of ASME Code Case N-640 in developing Pressure-Temperature (P-T) limit curves for LaSalle Unit 1 and Unit 2. However, this exemption was not listed in the LRA because it was thought that this exemption is not currently “in effect” as specified in the definition, since the P-T limit curves and supporting analyses that had credited the exemption are not currently in effect, having been superseded by updated P-T limit curves that did not credit the exemption. Based upon further evaluation, it was determined that the exemption is still in effect since it has not been withdrawn.

As a result of this evaluation, LRA Section 4.1.5 is revised to meet the requirement of 10 CFR 54.21(c)(2) to list the plant-specific exemptions granted pursuant to 10 CFR 50.12, are in effect, and are based on time-limited aging analyses as defined in 10 CFR 54.3, as shown in Enclosure B. This exemption is described below. The evaluation is also provided below that explains why this exemption is not required during the period of extended operation.

- By letter dated November 8, 2000 (ADAMS Accession No. ML003771016), in accordance with 10 CFR 50.12, the staff granted an exemption for LaSalle Unit 1 and Unit 2 to the requirements of 10 CFR 50, Appendix G that permits the use of American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code, Code Case N-640, "Alternative Requirement Fracture Toughness for Development of P-T Limit Curves for ASME B&PV Code Section XI, Division 1," in calculating RPV P-T limits. The methodology that was used to recalculate the RPV P-T limits and submitted in the license amendment request dated February 29, 2000 was based on the ASME Code Case N-640 cited above. Therefore, the P-T limits approved by the November 8, 2000 SER are based upon a TLAA and require evaluation for the period of extended operation.

- The license amendment request associated with this exemption, dated February 29, 2000, as supplemented on June 26 and August 18, 2000, requested exemption to 10 CFR 50 Appendix G to permit the use of ASME Code Cases N-588 and N-640. In the SER dated November 8, 2000, the staff determined that Code Case N-588 is not relevant to the evaluation of the LaSalle Unit 1 or Unit 2 RPVs because neither of the LaSalle RPVs is limited in the beltline region by a circumferential weld. Therefore, Code Case N-588 does not affect the evaluation of the beltline region for the LaSalle Unit 1 RPV, which is limited by an axial weld, nor does it affect the LaSalle Unit 2 RPV, which is limited by the lower-intermediate shell plate material. Therefore, the staff determined that an exemption to use Code Case N-588 was not necessary for LaSalle Unit 1 and Unit 2. The exemption that was granted only applies to ASME Code Case N-640.

- This exemption to 10 CFR 50, Appendix G will not need to be continued into the period of extended operation for LaSalle Unit 1 and Unit 2. The 2004 Edition of the ASME Code introduced a more recent version of Appendix G to Section XI of the ASME Code than the one in effect when this exemption was approved that incorporates the provisions of ASME Code Case N-640. The 2004 Edition has been endorsed in 10 CFR 50.55a, and therefore, by reference in 10 CFR Part 50, Appendix G.

- The pressure-temperature (P-T) limits that were submitted for approval on February 29, 2000 that were based upon the exemption have been superseded by P-T limits that were prepared in accordance with the 2004 or later Editions of the ASME Code that incorporated Code Case N-640. The current Unit 1 P-T limits were approved by the NRC on November 25, 2014 in Amendment No. 210 to License No. NPF-11. The current Unit 2 P-T limits were approved by the NRC on April 15, 2011 in Amendment 188 to License No. NPF-18. Therefore, since the current P-T limits are not based on this exemption and since any future P-T limit curves will also be based upon ASME Code Editions that have incorporated Code Case N-640, the exemption granting the use of ASME Code Case N-640 will not need to be extended into the period of extended operation.

An extent-of-condition review was completed to determine if there are any other plant-specific exemptions granted pursuant to 10 CFR 50.12 and in effect that are based on a TLAA as defined in 10 CFR 54.3, in accordance with 10 CFR 54.21(c)(2). No additional exemptions were identified that are required to be added to LRA Section 4.1.5.

LRA Section 4.1.5 is revised and Table 4.1-3 is added to document this information, as shown in Enclosure B.

Enclosure B

LSCS License Renewal Application Updates
Resulting from the Response to the following RAIs:

RAI B.2.1.10-1
RAI B.2.1.13-2
RAI B.2.1.13-3
RAI B.2.1.13-4
RAI B.2.1.18-1
RAI B.2.1.18-2
RAI B.2.1.23-1
RAI B.2.1.23-2
RAI 4.1-3

Notes:

- Updated LRA Sections and Tables are provided in the same order as the RAI responses contained in Enclosure A, unless there are multiple changes as a result of different RAI responses to a given LRA Section or Table.
- To facilitate understanding, portions of the original LRA have been repeated in this Enclosure, with revisions indicated. Previously submitted information is shown in normal font. Changes are highlighted with ***bolded italics*** for inserted text and ~~strikethroughs~~ for deleted text.

As a result of the response to RAI B.2.1.10-1 provided in Enclosure A of this letter, LRA Appendix A, Section A.2.1.10 on page A-14 of the LRA is revised as shown below:

A.2.1.10 Flow-Accelerated Corrosion

The Flow-Accelerated Corrosion (FAC) aging management program is an existing condition monitoring program based on EPRI guidelines in NSAC-202L-~~R3~~***R4***, “Recommendations for an Effective Flow- Accelerated Corrosion Program.” The program provides guidance for prediction, detection, and monitoring of wall thinning in piping and components. Analytical evaluations and periodic examinations of locations that are most susceptible to wall thinning due to FAC are used to predict the amount of wall thinning. Program activities include analyses to determine critical locations, baseline inspections to determine the extent of thinning at these critical locations, and follow-up inspections to confirm the predictions. Repairs and replacements are performed as necessary.

The Flow-Accelerated Corrosion program also manages wall thinning caused by mechanisms other than FAC, such as cavitation, flashing, droplet impingement, and solid particle impingement, in situations where periodic monitoring is used in lieu of eliminating the cause of various erosion mechanisms.

As a result of the response to RAI B.2.1.10-1 provided in Enclosure A of this letter, LRA Appendix B, Section B.2.1.10 “NUREG-1801 Consistency” and “Exceptions to NUREG-1801” paragraphs on page B-51 of the LRA is revised as shown below:

NUREG-1801 Consistency

The Flow-Accelerated Corrosion aging management program is consistent with the ten elements of aging management program XI.M17, "Flow-Accelerated Corrosion,” specified in NUREG-1801, as modified by LR-ISG-2012-01 ***with the following exception***~~.~~***:***

Exceptions to NUREG-1801

~~None.~~

1. The NUREG-1801 aging management program XI.M17, Flow-Accelerated Corrosion relies on implementation of the Electric Power Research Institute (EPRI) guidelines in the Nuclear Safety Analysis Center (NSAC)-202L-R2 or -R3 for an effective FAC program. The LSCS Flow-Accelerated Corrosion program is based on NSAC-202L-R4. Program Elements Affected: Scope of Program (Element 1), Detection of Aging Effects (Element 4), Monitoring and Trending (Element 5), Acceptance Criteria (Element 6)

Justification for Exception

EPRI periodically revises NSAC-202L to update FAC program recommendations with the experience of members of the CHECWORKS™ Users Group (CHUG), and recent developments in detection, modeling, and mitigation technology. These recommendations enhance those of earlier versions and ensure the continuity of the LSCS FAC program. The technical changes that affect the program elements of NUREG-1801 aging management program XI.M17, and the non-technical changes, represent improvements in the management of flow-accelerated corrosion. Therefore, this ensures that the main objective of the Flow-Accelerated Corrosion aging management program, which is to manage wall thinning, is maintained. The LSCS Flow-Accelerated Corrosion aging management program, as based on NSAC-202L-R4, will continue to manage the effects of aging so that the intended functions will be maintained consistent with the Current Licensing Basis (CLB) during the period of extended operation.

As a result of the response to RAI B.2.1.10-1 provided in Enclosure A of this letter, LRA Table 3.2.2-1 beginning on page 3.2-33 of the LRA is revised as shown below:

Table 3.2.2-1 High Pressure Core Spray System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Bolting	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.11)	V.E.EP-70	3.2.1-13	A
				Loss of Preload	Bolting Integrity (B.2.1.11)	V.E.EP-69	3.2.1-15	A
		Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.11)	V.E.EP-70	3.2.1-13	A
				Loss of Preload	Bolting Integrity (B.2.1.11)	V.E.EP-69	3.2.1-15	A
			Treated Water (External)	Loss of Material	Bolting Integrity (B.2.1.11)	V.D2.EP-73	3.2.1-17	E, 1, 2
				Loss of Preload	Bolting Integrity (B.2.1.11)	V.E.EP-122	3.2.1-15	A, 1
Flow Device	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.D2.E-26	3.2.1-40	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-16	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-16	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-408	3.2.1-65	~~A~~***B***
	Throttle	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-16	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-16	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-408	3.2.1-65	~~A~~***B***
Piping, piping components, and piping elements	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.D2.E-26	3.2.1-40	A

Table 3.2.2-1 High Pressure Core Spray System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Piping, piping components, and piping elements	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	VII.E3.A-62	3.3.1-2	A, 5
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-17	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	B
		Zinc	Air - Indoor Uncontrolled (External)	None	External Surfaces Monitoring of Mechanical Components (B.2.1.24)			F, 3
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)			F, 4
					One-Time Inspection (B.2.1.21)			F, 4
Pump Casing (HPCS Pump)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.D2.E-26	3.2.1-40	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-16	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-16	B
Pump Casing (Water Leg Pump)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.D2.E-26	3.2.1-40	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-16	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-16	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-408	3.2.1-65	~~A~~***B***
		Carbon or Low Alloy Steel with Stainless Steel Cladding	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.D2.E-26	3.2.1-40	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-17	A

Table 3.2.2-1 High Pressure Core Spray System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Pump Casing (Water Leg Pump)	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-408	3.2.1-65	~~A~~***B***
		Stainless Steel	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-18	3.2.1-63	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-17	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-408	3.2.1-65	~~A~~***B***
Strainer Element	Filter	Stainless Steel	Treated Water (External)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-17	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	B
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-17	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	B
	Pressure Boundary	Stainless Steel	Treated Water (External)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-17	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	B
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-17	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	B
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.D2.E-26	3.2.1-40	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-16	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-16	B

As a result of the response to RAI B.2.1.10-1 provided in Enclosure A of this letter, LRA Table 3.2.2-2 beginning on page 3.2-39 of the LRA is revised as shown below:

Table 3.2.2-2 Low Pressure Core Spray System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Bolting	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air – Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.11)	V.E.EP-70	3.2.1-13	A
				Loss of Preload	Bolting Integrity (B.2.1.11)	V.E.EP-69	3.2.1-15	A
		Stainless Steel Bolting	Treated Water (External)	Loss of Material	Bolting Integrity (B.2.1.11)	V.D2.EP-73	3.2.1-17	E, 1, 2
				Loss of Preload	Bolting Integrity (B.2.1.11)	V.E.EP-122	3.2.1-15	A, 1
Flow Device	Pressure Boundary	Carbon Steel	Air – Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-40	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-16	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-16	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-408	3.2.1-65	~~A~~***B***
	Throttle	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-40	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-16	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-16	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-408	3.2.1-65	~~A~~***B***
Piping, piping components, and piping elements	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-40	A

Table 3.2.2-2 Low Pressure Core Spray System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Piping, piping components, and piping elements	Pressure Boundary	Copper Alloy with less than 15% Zinc	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.A.SP-101	3.4.1-16	B
		Glass	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-15	3.2.1-60	A
			Lubricating Oil (Internal)	None	None	V.F.EP-16	3.2.1-60	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-18	3.2.1-63	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-17	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	B
		Zinc	Air - Indoor Uncontrolled (External)	None	External Surfaces Monitoring of Mechanical Components (B.2.1.24)			F, 3
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)			F, 4
					One-Time Inspection (B.2.1.21)			F, 4
Pump Casing (LPCS Pump)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-40	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-16	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-16	B
Pump Casing (Water Leg Pump)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-40	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-16	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-16	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-408	3.2.1-65	~~A~~***B***

Table 3.2.2-2 Low Pressure Core Spray System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Pump Casing (Water Leg Pump)	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-40	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-17	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-408	3.2.1-65	~~A~~***B***
		Stainless Steel	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-18	3.2.1-63	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-17	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-408	3.2.1-65	~~A~~***B***
Strainer Element	Filter	Stainless Steel	Treated Water (External)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-17	A, 1
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	B, 1
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-17	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	B
	Pressure Boundary	Stainless Steel	Treated Water (External)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-17	A, 1
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	B, 1
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-17	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	B
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-40	A

As a result of the response to RAI B.2.1.10-1 provided in Enclosure A of this letter, LRA Table 3.2.2-3 beginning on page 3.2-45 of the LRA is revised as shown below:

Table 3.2.2-3 **Reactor Core Isolation Cooling System**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Bolting	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.11)	V.E.EP-70	3.2.1-13	A
				Loss of Preload	Bolting Integrity (B.2.1.11)	V.E.EP-69	3.2.1-15	A
		Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.11)	V.E.EP-70	3.2.1-13	A
				Loss of Preload	Bolting Integrity (B.2.1.11)	V.E.EP-69	3.2.1-15	A
			Treated Water (External)	Loss of Material	Bolting Integrity (B.2.1.11)	V.D2.EP-73	3.2.1-17	E, 1, 2
				Loss of Preload	Bolting Integrity (B.2.1.11)	V.E.EP-122	3.2.1-15	A, 1
Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-18	3.2.1-63	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-17	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-408	3.2.1-65	~~A~~***B***
	Throttle	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-17	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-408	3.2.1-65	~~A~~***B***
Heat Exchanger - (Lube Oil Cooler) Shell Side Components	Pressure Boundary	Copper Alloy with 15% Zinc or More	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-57	C

Table 3.2.2-3 Reactor Core Isolation Cooling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Heat Exchanger - (Lube Oil Cooler) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Treated Water (Internal)	Cracking	One-Time Inspection (B.2.1.21)			H, 7
					Water Chemistry (B.2.1.2)			H, 7
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.A.SP-101	3.4.1-16	C
					Water Chemistry (B.2.1.2)	VIII.A.SP-101	3.4.1-16	D
					Selective Leaching (B.2.1.22)	VII.F1.AP-65	3.3.1-72	A
Hoses	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-18	3.2.1-63	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.EP-61	3.2.1-48	A
Piping, piping components, and piping elements	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-40	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-46	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-16	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-16	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-09	3.2.1-11	~~A~~***B***
		Glass	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-15	3.2.1-60	A
			Treated Water (Internal)	None	None	V.F.EP-29	3.2.1-60	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-18	3.2.1-63	A

Table 3.2.2-3 Reactor Core Isolation Cooling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Piping, piping components, and piping elements	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-17	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	B
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-40	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-77	3.2.1-49	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-77	3.2.1-49	A
			Steam (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.B2.SP-160	3.4.1-14	A
					Water Chemistry (B.2.1.2)	VIII.B2.SP-160	3.4.1-14	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-07	3.2.1-11	~~A~~***B***
			Treated Water (External)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-16	A, 1
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-16	B, 1
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	V.D2.E-10	3.2.1-1	A, 8
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-16	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-16	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-09	3.2.1-11	~~A~~***B***
		Glass	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-15	3.2.1-60	A
			Lubricating Oil (Internal)	None	None	V.F.EP-16	3.2.1-60	A
			Treated Water (Internal)	None	None	V.F.EP-29	3.2.1-60	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-18	3.2.1-63	A

Table 3.2.2-3 Reactor Core Isolation Cooling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Pump Casing (Water Leg Pump)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-408	3.2.1-65	~~A~~***B***
		Carbon or Low Alloy Steel with Stainless Steel Cladding	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-40	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-17	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-408	3.2.1-65	~~A~~***B***
		Stainless Steel	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-18	3.2.1-63	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-17	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-408	3.2.1-65	~~A~~***B***
Rupture Disks	Pressure Boundary	Nickel Alloy	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-17	3.2.1-61	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-274	3.3.1-95	A
Strainer Element	Filter	Carbon Steel	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-77	3.2.1-49	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-77	3.2.1-49	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-77	3.2.1-49	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-77	3.2.1-49	A

Table 3.2.2-3 Reactor Core Isolation Cooling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-40	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-46	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-16	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-16	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-09	3.2.1-11	~~A~~***B***
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-40	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-46	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-77	3.2.1-49	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-77	3.2.1-49	A
			Steam (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.B2.SP-160	3.4.1-14	A
					Water Chemistry (B.2.1.2)	VIII.B2.SP-160	3.4.1-14	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-07	3.2.1-11	~~A~~***B***
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-16	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-16	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-09	3.2.1-11	~~A~~***B***

As a result of the response to RAI B.2.1.10-1 provided in Enclosure A of this letter, LRA Table 3.2.2-4 beginning on page 3.2-60 of the LRA is revised as shown below:

Table 3.2.2-4 Residual Heat Removal System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Piping, piping components, and piping elements	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-18	3.2.1-63	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-17	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	B
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.D2.E-26	3.2.1-40	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.E-27	3.2.1-46	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-77	3.2.1-49	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-77	3.2.1-49	A
			Treated Water (External)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-16	A, 1
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-16	B, 1
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	V.D2.E-10	3.2.1-1	A, 4
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-16	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-16	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-09	3.2.1-11	~~A~~***B***
		Glass	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-15	3.2.1-60	A
			Lubricating Oil (Internal)	None	None	V.F.EP-16	3.2.1-60	A
			Treated Water (Internal)	None	None	V.F.EP-29	3.2.1-60	A

Table 3.2.2-4 Residual Heat Removal System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Spray Nozzles	Spray	Stainless Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	V.D2.EP-61	3.2.1-48	A
Strainer Element	Filter	Stainless Steel	Treated Water (External)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-17	A, 1
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	B, 1
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-17	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	B
	Pressure Boundary	Stainless Steel	Treated Water (External)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-17	A, 1
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	B, 1
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-17	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	B
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-18	3.2.1-63	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-17	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	B
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.D2.E-26	3.2.1-40	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-16	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-16	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-09	3.2.1-11	~~A~~***B***
		Stainless Steel	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-18	3.2.1-63	A

As a result of the response to RAI B.2.1.10-1 provided in Enclosure A of this letter, LRA Table 3.3.2-21 beginning on page 3.3-221 of the LRA is revised as shown below:

Table 3.3.2-21 Reactor Water Cleanup System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Heat Exchanger - (RWCU Pump Heat Exchanger) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-78	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-106	3.3.1-21	C
					Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-21	D
Piping, piping components, and piping elements	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-78	A
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	V.D2.E-10	3.2.1-1	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-106	3.3.1-21	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-21	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-09	3.2.1-11	~~A~~***B***
		Glass	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-14	3.3.1-117	A
			Treated Water (Internal)	None	None	VII.J.AP-51	3.3.1-117	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-17	3.3.1-120	A
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	VII.E3.A-62	3.3.1-2	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-110	3.3.1-25	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-25	B
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E3.AP-120	3.3.1-19	C
					Water Chemistry (B.2.1.2)	VII.E3.AP-120	3.3.1-19	D

Table 3.3.2-21 Reactor Water Cleanup System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Piping, piping components, and piping elements	Leakage Boundary	Stainless Steel	Treated Water > 140 F (Internal)	Cumulative Fatigue Damage	TLAA	VII.E3.A-62	3.3.1-2	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-110	3.3.1-25	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-25	B
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-78	A
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	V.D2.E-10	3.2.1-1	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-106	3.3.1-21	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-21	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-09	3.2.1-11	~~A~~***B***
		Stainless Steel	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-17	3.3.1-120	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-110	3.3.1-25	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-25	B
Pump Casing (Clean-Up Filter Demineralizer Holding Pump)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-78	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-106	3.3.1-21	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-21	B
Pump Casing (Clean-Up Filter Demineralizer Precoat Pump)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-78	A

Table 3.3.2-21 Reactor Water Cleanup System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Pump Casing (Clean-Up Filter Demineralizer Precoat Pump)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-106	3.3.1-21	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-21	B
Pump Casing (Reactor Water Clean-Up Recirculation Pump)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-78	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-106	3.3.1-21	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-21	B
Tanks (Clean-Up Filter Demineralizer Precoat Tank)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-78	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-106	3.3.1-21	C
					Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-21	D
Tanks (Clean-Up Filter Demineralizer)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-78	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-106	3.3.1-21	C
					Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-21	D
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-78	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-106	3.3.1-21	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-21	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-09	3.2.1-11	~~A~~***B***

Table 3.3.2-21 Reactor Water Cleanup System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-17	3.3.1-120	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-110	3.3.1-25	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-25	B
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VII.E3.AP-120	3.3.1-19	C
					Water Chemistry (B.2.1.2)	VII.E3.AP-120	3.3.1-19	D
				Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-110	3.3.1-25	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-25	B
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-78	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-106	3.3.1-21	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-21	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-09	3.2.1-11	~~A~~***B***
		Stainless Steel	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-17	3.3.1-120	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VII.E3.AP-110	3.3.1-25	A
					Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-25	B

As a result of the response to RAI B.2.1.10-1 provided in Enclosure A of this letter, LRA Table 3.4.2-2 beginning on page 3.4-35 of the LRA is revised as shown below:

Table 3.4.2-2 **Condenser and Air Removal System**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Bolting	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.11)	VIII.H.SP-84	3.4.1-8	A
				Loss of Preload	Bolting Integrity (B.2.1.11)	VIII.H.SP-83	3.4.1-10	A
Heat Exchanger - (Main Condenser) Shell Side Components	Containment, Holdup and Plateout	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-29	3.4.1-34	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-77	3.4.1-15	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-77	3.4.1-15	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	VIII.D2.S-408	3.4.1-60	~~C~~***D***
Piping, piping components, and piping elements	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-29	3.4.1-34	A
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	VIII.B2.S-08	3.4.1-1	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-73	3.4.1-14	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-73	3.4.1-14	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	VIII.E.S-16	3.4.1-5	~~A~~***B***
		Stainless Steel	Air - Indoor Uncontrolled (External)	None	None	VIII.I.SP-12	3.4.1-58	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-87	3.4.1-16	A

Table 3.4.2-2 Condenser and Air Removal System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Piping, piping components, and piping elements	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-87	3.4.1-16	B
Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-29	3.4.1-34	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.E.SP-73	3.4.1-14	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-73	3.4.1-14	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	VIII.E.S-16	3.4.1-5	~~A~~***B***

As a result of the response to RAI B.2.1.10-1 provided in Enclosure A of this letter, LRA Table 3.4.2-3 beginning on page 3.4-38 of the LRA is revised as shown below:

Table 3.4.2-3 Feedwater System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Bolting	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air – Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.11)	VIII.H.SP-84	3.4.1-8	A
				Loss of Preload	Bolting Integrity (B.2.1.11)	VIII.H.SP-83	3.4.1-10	A
Piping, piping components, and piping elements	Leakage Boundary	Carbon Steel	Air – Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-29	3.4.1-34	A
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	VIII.D2.S-11	3.4.1-1	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.SP-73	3.4.1-14	A
					Water Chemistry (B.2.1.2)	VIII.D2.SP-73	3.4.1-14	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	VIII.D2.S-16	3.4.1-5	~~A~~***B***
		Stainless Steel	Air - Indoor Uncontrolled (External)	None	None	VIII.I.SP-12	3.4.1-58	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.SP-87	3.4.1-16	A
					Water Chemistry (B.2.1.2)	VIII.D2.SP-87	3.4.1-16	B
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VIII.E.SP-88	3.4.1-11	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-88	3.4.1-11	B
				Cumulative Fatigue Damage	TLAA	VII.E3.A-62	3.3.1-2	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.SP-87	3.4.1-16	A

Table 3.4.2-3 Feedwater System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Piping, piping components, and piping elements	Leakage Boundary	Stainless Steel	Treated Water > 140 F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.D2.SP-87	3.4.1-16	B
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-29	3.4.1-34	A
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	VIII.D2.S-11	3.4.1-1	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.SP-73	3.4.1-14	A
					Water Chemistry (B.2.1.2)	VIII.D2.SP-73	3.4.1-14	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	VIII.D2.S-16	3.4.1-5	~~A~~***B***
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-29	3.4.1-34	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.SP-73	3.4.1-14	A
					Water Chemistry (B.2.1.2)	VIII.D2.SP-73	3.4.1-14	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	VIII.D2.S-16	3.4.1-5	~~A~~***B***
		Stainless Steel	Air - Indoor Uncontrolled (External)	None	None	VIII.I.SP-12	3.4.1-58	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.SP-87	3.4.1-16	A
					Water Chemistry (B.2.1.2)	VIII.D2.SP-87	3.4.1-16	B
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-29	3.4.1-34	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.D2.SP-73	3.4.1-14	A
					Water Chemistry (B.2.1.2)	VIII.D2.SP-73	3.4.1-14	B

Table 3.4.2-3 Feedwater System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	VIII.D2.S-16	3.4.1-5	~~A~~***B***

As a result of the response to RAI B.2.1.10-1 provided in Enclosure A of this letter, LRA Table 3.4.2-4 beginning on page 3.4-42 of the LRA is revised as shown below:

Table 3.4.2-4 **Main Steam System**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Bolting	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.11)	VIII.H.SP-84	3.4.1-8	A
				Loss of Preload	Bolting Integrity (B.2.1.11)	VIII.H.SP-83	3.4.1-10	A
Piping, piping components, and piping elements	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-29	3.4.1-34	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.B2.SP-73	3.4.1-14	A
					Water Chemistry (B.2.1.2)	VIII.B2.SP-73	3.4.1-14	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	VIII.D2.S-16	3.4.1-5	~~A~~***B***
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-29	3.4.1-34	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VIII.B1.SP-60	3.4.1-37	A
			Steam (Internal)	Cumulative Fatigue Damage	TLAA	VIII.B2.S-08	3.4.1-1	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.B2.SP-160	3.4.1-14	A
					Water Chemistry (B.2.1.2)	VIII.B2.SP-160	3.4.1-14	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	VIII.B2.S-15	3.4.1-5	~~A~~***B***

Table 3.4.2-4 Main Steam System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Piping, piping components, and piping elements	Pressure Boundary	Carbon Steel	Treated Water (External)	Cumulative Fatigue Damage	TLAA	VIII.B2.S-08	3.4.1-1	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.B2.SP-73	3.4.1-14	A
					Water Chemistry (B.2.1.2)	VIII.B2.SP-73	3.4.1-14	B
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	VIII.B2.S-08	3.4.1-1	A, 1
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.B2.SP-73	3.4.1-14	A
					Water Chemistry (B.2.1.2)	VIII.B2.SP-73	3.4.1-14	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	VIII.D2.S-16	3.4.1-5	~~A~~***B***

Table 3.4.2-4 Main Steam System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-29	3.4.1-34	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.B2.SP-73	3.4.1-14	A
					Water Chemistry (B.2.1.2)	VIII.B2.SP-73	3.4.1-14	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	VIII.D2.S-16	3.4.1-5	~~A~~***B***
		Stainless Steel	Air - Indoor Uncontrolled (External)	None	None	VIII.I.SP-12	3.4.1-58	A
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.21)	VIII.C.SP-88	3.4.1-11	A
					Water Chemistry (B.2.1.2)	VIII.C.SP-88	3.4.1-11	B
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.C.SP-87	3.4.1-16	A
					Water Chemistry (B.2.1.2)	VIII.C.SP-87	3.4.1-16	B

As a result of the response to RAI B.2.1.10-1 provided in Enclosure A of this letter, LRA Table 3.4.2-5 on page 3.4-46 of the LRA is revised as shown below:

Table 3.4.2-5 Main Turbine and Auxiliaries System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Turbine Casings (Low Pressure Turbine Exhaust Hoods)	Containment, Holdup and Plateout	Carbon Steel	Air – Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VIII.H.S-29	3.4.1-34	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	VIII.B2.SP-73	3.4.1-14	C
					Water Chemistry (B.2.1.2)	VIII.B2.SP-73	3.4.1-14	D
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	VIII.E.S-16	3.4.1-5	~~C~~***D***

As a result of the response to RAI B.2.1.10-1 provided in Enclosure A of this letter, LRA Table 3.1.1, Item Number 3.1.1-60, on page 3.1-30 of the LRA is revised as shown below:

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-60	Steel piping, piping components, and piping elements exposed to reactor coolant	Wall thinning due to flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion"	No	Consistent with NUREG-1801 ***with exceptions***. The Flow-Accelerated Corrosion (B.2.1.10) program will be used to manage wall thinning of carbon steel piping, piping components, and piping elements exposed to reactor coolant in the Reactor Coolant Pressure Boundary System. ***An exception applies to the NUREG-1801 recommendations for Flow-Accelerated Corrosion (B.2.1.10) program implementation.***

As a result of the response to RAI B.2.1.10-1 provided in Enclosure A of this letter, LRA Table 3.2.1, Item Number 3.2.1-11, on page 3.2-15 of the LRA is revised as shown below:

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-11	Steel Piping, piping components, and piping elements exposed to Steam, Treated water	Wall thinning due to flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion"	No	Consistent with NUREG-1801 ***with exceptions***. The Flow-Accelerated Corrosion (B.2.1.10) program will be used to manage wall thinning of the carbon steel piping, piping components, and piping elements exposed to steam and treated water in the Reactor Coolant Pressure Boundary System, Reactor Core Isolation Cooling System, Reactor Water Cleanup System, and Residual Heat Removal System. ***An exception applies to the NUREG-1801 recommendations for Flow-Accelerated Corrosion (B.2.1.10) program implementation.***

As a result of the response to RAI B.2.1.10-1 provided in Enclosure A of this letter, LRA Table 3.2.1, Item Number 3.2.1-65, on page 3.2-30 of the LRA is revised as shown below:

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-65	Any material, piping, piping components, and piping elements exposed to treated water, treated water (borated)	Wall thinning due to erosion	Chapter XI.M17, "Flow-Accelerated Corrosion"	No	Consistent with NUREG-1801 ***with exceptions***. The Flow-Accelerated Corrosion (B.2.1.10) program will be used to manage wall thinning of the carbon or low alloy steel with stainless steel cladding, carbon steel, and stainless steel piping, piping components, and piping elements exposed to treated water in the High Pressure Core Spray System, Low Pressure Core Spray System, and Reactor Core Isolation Cooling System. ***An exception applies to the NUREG-1801 recommendations for Flow-Accelerated Corrosion (B.2.1.10) program implementation.***

As a result of the response to RAI B.2.1.10-1 provided in Enclosure A of this letter, LRA Table 3.4.1, Item Number 3.4.1-5, on page 3.4-12 of the LRA is revised as shown below:

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-5	Steel Piping, piping components, and piping elements exposed to Steam, Treated water	Wall thinning due to flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion"	No	Consistent with NUREG-1801***with exceptions***. The Flow-Accelerated Corrosion (B.2.1.10) program will be used to manage wall thinning of the carbon steel piping, piping components, and piping elements, and turbine casings exposed to steam and treated water in the Condenser and Air Removal System, Feedwater System, Main Steam System, and Main Turbine and Auxiliaries System. ***An exception applies to the NUREG-1801 recommendations for Flow-Accelerated Corrosion (B.2.1.10) program implementation.***

As a result of the response to RAI B.2.1.10-1 provided in Enclosure A of this letter, LRA Table 3.4.1, Item Number 3.4.1-60, on page 3.4-26 of the LRA is revised as shown below:

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-60	Any material, piping, piping components, and piping elements exposed to treated water	Wall thinning due to erosion	Chapter XI.M17, “Flow-Accelerated Corrosion”	No	Consistent with NUREG-1801 ***with exceptions***. The Flow-Accelerated Corrosion (B.2.1.10) program will be used to manage wall thinning of the carbon steel heat exchanger components exposed to treated water in the Condensate and Air Removal System. ***An exception applies to the NUREG-1801 recommendations for Flow-Accelerated Corrosion (B.2.1.10) program implementation.***

As a result of the response to RAI B.2.1.13-2 provided in Enclosure A of this letter, LRA Appendix A, Section A.2.1.13 on page A-18 of the LRA is revised as shown below:

A.2.1.13 Closed Treated Water Systems

The Closed Treated Water Systems program is an existing mitigative and condition monitoring program that manages the loss of material, cracking, and reduction of heat transfer in piping, piping components, piping elements, tanks, and heat exchangers exposed to a closed cycle cooling water environment. The Closed Treated Water Systems program includes (a) nitrite-based water treatment, including pH control and the use of corrosion inhibitors, to modify the chemical composition of the water such that the function of the equipment is maintained and such that the effects of corrosion are minimized; (b) chemical testing of the water to ensure that the water treatment program maintains the water chemistry within acceptable guidelines; and (c) inspections to determine the presence or extent of corrosion, stress corrosion cracking, or fouling. The inspections include existing visual inspections of the internal surface of the components performed whenever the system boundary is opened as well as new periodic inspections as described in the enhancement below. The Closed Treated Water Systems aging management program will be enhanced to:

1. Perform condition monitoring, including periodic visual inspections and non-destructive examinations, to verify the effectiveness of water chemistry control to mitigate aging effects. A representative sample of piping and components will be selected based on likelihood of corrosion, stress corrosion cracking, or fouling, and inspected at an interval not to exceed once in 10 years during the period of extended operation. The selection of components to be inspected will focus on locations which are most susceptible to age-related degradation, where practical.

2. Monitor and trend drywell penetration cooling coil outlet temperatures monthly to ensure that adequate cooling is being provided to the concrete adjacent to the drywell penetrations.

~~This~~ ***These*** enhancement***s*** will be implemented prior to the period of extended operation.

As a result of the response to RAI B.2.1.13-2 provided in Enclosure A of this letter, LRA Appendix B, Section B.2.1.13 “Enhancements” paragraph on page B-65 is revised as shown below:

Enhancements

Prior to the period of extended operation, the following enhancement***s*** will be implemented in the following program elements:

1. Perform condition monitoring, including periodic visual inspections and non-destructive examinations, to verify the effectiveness of water chemistry control to mitigate aging effects. A representative sample of piping and components will be selected based on likelihood of corrosion, stress corrosion cracking, or fouling, and inspected at an interval not to exceed once in 10 years during the period of extended operation. The selection of components to be inspected will focus on locations which are most susceptible to age-related degradation, where practical. **Program Elements Affected: Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4)**

2. Monitor and trend drywell penetration cooling coil outlet temperatures monthly to ensure that adequate cooling is being provided to the concrete adjacent to the drywell penetrations. Program Elements Affected: Parameters Monitored or Inspected (Element 3), Monitoring and Trending (Element 5)

As a result of the response to RAI B.2.1.13-4 provided in Enclosure A of this letter, LRA Table 2.3.1-1 on page 2.3-6 of the LRA is revised as shown below:

Table 2.3.1-1 **Reactor Coolant Pressure Boundary System**
Components Subject to Aging Management Review

Component Type	Intended Function
Accumulator	Leakage Boundary
Bolting	Mechanical Closure
Class 1 Piping, Fittings and Branch Connections < NPS 4"	Pressure Boundary
Flow Device (Instrumentation Orifices)	Pressure Boundary
	Throttle
Flow Device (Main Steam Line Flow Restrictors)	Throttle
Heat Exchanger - (EHC Fluid) Tube Side Components	Leakage Boundary
Heat Exchanger - (Motor Oil Coolers) Shell Side Components	Leakage Boundary
Heat Exchanger - (Motor Winding Coolers) Tube Side Components	Leakage Boundary
Heat Exchanger - (Motor Winding Coolers) Tubes	Leakage Boundary
Heat Exchanger - (Seal Coolers) Shell Side Components	***Leakage Boundary***
Heat Exchanger - (Seal Coolers) Tube Side Components	***Pressure Boundary***
Hoses	Leakage Boundary
Piping, piping components, and piping elements	Leakage Boundary
	Pressure Boundary
Pump Casing (EHC Skid)	Leakage Boundary
Pump Casing (RRP)	Pressure Boundary
RPV Flange Leak Detection Line	Pressure Boundary
Tanks (EHC Reservoir)	Leakage Boundary
Valve Body	Leakage Boundary
	Pressure Boundary

As a result of the response to RAI B.2.1.13-3 provided in Enclosure A of this letter, LRA Section 3.3.2.1.12 on page 3.3-15 of the LRA is revised as shown below:

3.3.2.1.12 Fire Protection System

Materials

The materials of construction for the Fire Protection System components are:

- Aluminum Silicate
- Calcium Silicate
- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Ceramic Fiber
- Concrete Block
- ***Copper Alloy with 15% Zinc or More***
- Copper Alloy with less than 15% Zinc
- Ductile Cast Iron
- Elastomers
- Galvanized Steel
- Glass
- Gray Cast Iron
- Grout
- Gypsum
- Mineral Fiber
- Pyrocrete
- Reinforced Concrete
- Stainless Steel
- Stainless Steel Bolting

As a result of the responses to RAI B.2.1.13-3 and RAI B.2.1.13-4 provided in Enclosure A of this letter, LRA Table 3.3.1 on pages 3.3-43, 3.3-53, 3.3-55, and 3.3-63 of the LRA is revised as shown below:

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.3.1-20	Stainless steel, Stainless steel; steel with stainless steel cladding Heat exchanger components exposed to Treated borated water >60°C (>140°F), Treated water >60°C (>140°F)	Cracking due to stress corrosion cracking	Chapter XI.M2, “Water Chemistry,” and Chapter XI.M32, “One-Time Inspection”	No	Consistent with NUREG-1801 with exceptions. The One-Time Inspection (B.2.1.21) program and Water Chemistry (B.2.1.2) program will be used to manage cracking of the carbon or low alloy steel with stainless steel cladding and stainless steel non-regenerative heat exchanger components exposed to treated water > 140°F in the ***Reactor Coolant Pressure Boundary System and*** Reactor Water Cleanup System. An exception applies to the NUREG-1801 recommendations for Water Chemistry (B.2.1.2) program implementation.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-43	Stainless steel Piping, piping components, and piping elements exposed to Closed-cycle cooling water >60°C (>140°F)	Cracking due to stress corrosion cracking	Chapter XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-1801. The Closed Treated Water Systems (B.2.1.13) program will be used to manage cracking of stainless steel piping, piping components, and piping elements exposed to closed cycle cooling water > 140°F in the Closed Cycle Cooling Water System.
3.3.1-44	Stainless steel; steel with stainless steel cladding Heat exchanger components exposed to Closed-cycle cooling water >60°C (>140°F)	Cracking due to stress corrosion cracking	Chapter XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-1801. The Closed Treated Water Systems (B.2.1.13) program will be used to manage cracking of stainless steel heat exchanger components exposed to closed cycle cooling water > 140°F in the Closed Cycle Cooling Water System ***and Reactor Coolant Pressure Boundary System***.
3.3.1-45	Steel Piping, piping components, and piping elements; tanks exposed to Closed-cycle cooling water	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M21A, "Closed Treated Water Systems	No	Consistent with NUREG-1801. The Closed Treated Water Systems (B.2.1.13) program will be used to manage loss of material of carbon steel, ductile cast iron, and gray cast iron piping, piping components, and piping elements and tanks exposed to closed cycle cooling water in the Closed Cycle Cooling Water System, Diesel Generator and Auxiliaries System, Drywell Pneumatic System, Nonsafety-Related Ventilation System, Primary Containment Ventilation System, and Process Sampling and Post Accident Monitoring System.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-49	Stainless steel Piping, piping components, and piping elements exposed to Closed-cycle cooling water	Loss of material due to pitting and crevice corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-1801. The Closed Treated Water Systems (B.2.1.13) program will be used to manage loss of material of stainless steel heat exchanger components, piping, piping components, and piping elements exposed to closed cycle cooling water and closed cycle cooling water > 140°F in the Closed Cycle Cooling Water System, Diesel Generator and Auxiliaries System, Nonsafety-Related Ventilation System, Primary Containment Ventilation System, Process Radiation Monitoring System, ~~and~~ Process Sampling and Post Accident Monitoring System***, and Reactor Coolant Pressure Boundary System***.
3.3.1-50	Stainless steel, Copper Alloy, Steel Heat exchanger tubes exposed to Closed-cycle cooling water	Reduction of heat transfer due to fouling	Chapter XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-1801. The Closed Treated Water Systems (B.2.1.13) program will be used to manage reduction of heat transfer of copper alloy with 15% zinc or more heat exchanger tubes exposed to closed cycle cooling water in the Diesel Generator and Auxiliaries System.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.3.1-71	Stainless steel, Aluminum Piping, piping components, and piping elements exposed to Fuel oil	Loss of material due to pitting, crevice, and microbiologically-influenced corrosion	Chapter XI.M30, "Fuel Oil Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Consistent with NUREG-1801. The Fuel Oil Chemistry (B.2.1.19) program and One-Time Inspection (B.2.1.21) program will be used to manage loss of material of stainless steel piping, piping components, and piping elements exposed to fuel oil in the Diesel Generator and Auxiliaries System.
3.3.1-72	Gray cast iron, Copper alloy (>15% Zn or >8% Al) Piping, piping components, and piping elements, Heat exchanger components exposed to Treated water, Closed-cycle cooling water, Soil, Raw water, Waste water	Loss of material due to selective leaching	Chapter XI.M33, "Selective Leaching"	No	Consistent with NUREG-1801. The Selective Leaching (B.2.1.22) program will be used to manage loss of material of copper alloy with 15% zinc or more, copper alloy with 15% zinc or more (with internal coating), and gray cast iron traveling water screen framework, heat exchanger components, piping, piping components, and piping elements, and tanks exposed to closed cycle cooling water, raw water, soil, treated water, and waste water in the Closed Cycle Cooling Water System, Demineralized Water Makeup System, Diesel Generator and Auxiliaries System, Drywell Pneumatic System, Essential Cooling Water System, Fire Protection System, Nonessential Cooling Water System, Primary Containment Ventilation System, Process Sampling and Post Accident Monitoring System, ***Reactor Coolant Pressure Boundary System,*** Reactor Core Isolation Cooling System, Standby Liquid Control System, and Suppression Pool Cleanup System.

As a result of the response to RAI B.2.1.13-3 provided in Enclosure A of this letter, LRA Table 3.3.2-12 on pages 3.3-167, 3.3-168, and 3.3-171 of the LRA is revised as shown below:

Table 3.3.2-12 Fire Protection System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Sprinkler Heads	Pressure Boundary	Copper Alloy with less than 15% Zinc	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-403	3.3.1-130	B
			Condensation (Internal)	Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-403	3.3.1-130	B
			Raw Water (Internal)	Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-403	3.3.1-130	B
	Spray	Copper Alloy with less than 15% Zinc	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-403	3.3.1-130	B
			Condensation (Internal)	Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-403	3.3.1-130	B
Strainer Element	Filter	Stainless Steel	Raw Water (External)	Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-55	3.3.1-66	B
Tanks (Cardox Storage)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Protection (B.2.1.16)	VII.G.AP-150	3.3.1-58	A, 9
			Air/Gas - Dry (Internal)	None	None	VII.J.AP-6	3.3.1-121	C
Tanks (Retard Chamber)	Pressure Boundary	Copper Alloy with ~~less than 15% Zinc~~ ***15% Zinc or More***	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	C
			Raw Water (Internal)	***Cracking***	***Closed Treated Water Systems (B.2.1.13)***			***H, 11***
				Loss of Material	Fire Water System (B.2.1.17)	VII.G.AP-197	3.3.1-64	D
					Selective Leaching (B.2.1.22)	***VII.C2.AP-43***	***3.3.1-72***	***C***

Table 3.3.2-12 Fire Protection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Tanks (Retard Chamber)	Pressure Boundary	Ductile Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-78	A
			Raw Water (Internal)	Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-64	D
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-78	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-280	3.3.1-95	A
	Pressure Boundary	***Copper Alloy with 15% Zinc or More***	***Air - Indoor Uncontrolled (External)***	***None***	***None***	***VII.J.AP-144***	***3.3.1-114***	***A***
			Air/Gas - Dry (Internal)	***None***	***None***	***VII.J.AP-8***	***3.3.1-114***	***A***
		Copper Alloy with less than 15% Zinc	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Air/Gas - Dry (Internal)	None	None	VII.J.AP-8	3.3.1-114	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.G.AP-143	3.3.1-89	A
			Raw Water (Internal)	Loss of Material	Fire Water System (B.2.1.17)	VII.G.AP-197	3.3.1-64	B
		Ductile Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	VII.I.A-77	3.3.1-78	A
			Raw Water (Internal)	Loss of Material	Fire Water System (B.2.1.17)	VII.G.A-33	3.3.1-64	B

Table 3.3.2-12 **Fire Protection System** **(Continued)**

Plant Specific Notes: (continued)

5. NUREG-1801 does not include grout fire barriers, however, grout is similar to concrete in terms of characteristics and is considered to be susceptible to the same aging effects and mechanisms as reinforced concrete. These aging effects and mechanisms are managed by the Fire Protection (B.2.1.16) and Structures Monitoring (B.2.1.34) programs.

6. This component is associated with carbon steel (ASTM A-106 Gr. B) diesel-driven fire pump engine exhaust piping in a diesel exhaust environment. TLAA is used to manage cumulative fatigue damage for this component type, material, and environment combination. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.3.

7. The aging effects for galvanized steel (ASTM A-53 Gr. B) in a raw water environment include loss of coating integrity. The Service Level III and Service Level III Augmented Coatings Monitoring and Maintenance Program (B.2.2.1) is used to manage the identified aging effect applicable to galvanized steel in a raw water environment.

8. NUREG-1801, as amended by LR-ISG-2012-02, specifies a plant-specific program. The Fire Water System (B.2.1.17) program is used to manage the aging effect applicable to this component type, material, and environment combination.

9. The Fire Protection (B.2.1.16) program manages the external surfaces of carbon dioxide fire suppression system carbon steel piping, piping components, and piping elements and tanks exposed to an air - indoor uncontrolled (external) environment.

10. The Fire Protection (B.2.1.16) program is added to supplement the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program in managing the aging effect(s) applicable to this component type, material, and environment combination. The damper housings for dampers with a fire barrier intended function are evaluated with the Fire Protection System and are inspected in accordance with Fire Protection (B.2.1.16) program requirements. Fire barrier damper housings located within the in scope boundary of the various ventilation systems also have a pressure boundary intended function and are inspected in accordance with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program. The pressure boundary intended function is evaluated with the various ventilation systems.

11. The aging effects for copper alloy with 15% zinc or more in a closed cycle cooling water environment include cracking. The Closed Treated Water Systems (B.2.1.13) program is used to manage cracking for this component, material, and environment combination.

As a result of the responses to RAIs B.2.1.18-1 and B.2.1.18-2 provided in Enclosure A of this letter, LRA Appendix A, Section A.2.1.18 on page A-23 of the LRA is revised to amend the program description, Enhancement 3, and Enhancement 4 as shown below:

A.2.1.18 Aboveground Metallic Tanks

The Aboveground Metallic Tanks aging management program includes outdoor tanks sited on soil or concrete and indoor large volume tanks containing water designed with internal pressures approximating atmospheric pressure that are sited on concrete. The program is an existing condition monitoring program which will be enhanced to provide for management of loss of material and loss of sealing for metallic tanks within the scope of the program. The Unit 1 and Unit 2 cycled condensate storage tanks are the only tanks within the scope of this program. These tanks are fabricated from aluminum plates and are not coated or insulated, and are not susceptible to cracking. The program includes caulking at the tank interface with the tank foundation as a preventive measure to mitigate corrosion. Visual inspections are performed to monitor degradation of the tank surfaces and caulking ***(caulking inspections are supplemented with physical manipulation)***. Visual inspections of interior tank surfaces are performed to detect loss of material. The bottoms of the tanks are examined volumetrically. These inspections and examinations ensure that significant degradation is not occurring and that the intended function of the cycled condensate storage tanks is maintained during the period of extended operation.

The Aboveground Metallic Tanks aging management program will be enhanced to:

1. Perform a visual inspection of the tank shell, roof, and bottom interior surfaces for signs of loss of material on one of the cycled condensate storage tanks within five years prior to the period of extended operation. This inspection shall include both wetted and non-wetted surfaces and may be either direct visual inspection from inside the tanks or volumetric examination from outside the tank. A volumetric examination from outside the tank will include 25 percent of the tank surface area. Should the one-time inspection identify degradation, periodic inspections with an inspection frequency based on the rate of degradation will be established for both tanks.

2. Perform a visual inspection of the exterior surfaces of both cycled condensate storage tanks for loss of material each refueling interval.

3. Perform a volumetric examination of the tank bottom for both cycled condensate storage tanks for signs of loss of material whenever the tanks are drained. At a minimum, an inspection shall be performed within 10 years prior to the period of extended operation and subsequent inspections shall be performed in each 10-year period during the period of extended operation. ***The next inspection scope will include 100% of the accessible areas of each of the tank bottoms that are within 30 inches of the shell. Included in this scope are the patch plates that are directly exposed to the sand bed below. Additionally, 10 random locations of approximately one square foot each, outside of the 30 inch band, will be inspected. This inspection program will encompass approximately 20% of the tank bottom and will inspect all the susceptible areas which were found during the baseline inspections. Based on the results of this inspection, the scope will be reassessed for future tank bottom inspections, per the Corrective Action Program.***

4. Perform an inspection of the caulking at the perimeter of the cycled condensate storage tank bases for signs of degradation each refueling interval ***(caulking inspections are supplemented with physical manipulation)***.

These enhancements will be implemented prior to the period of extended operation.

As a result of the responses to RAI B.2.1.18-1 and B.2.1.18-2 provided in Enclosure A of this letter, LRA Section B.2.1.18 beginning on page B-86 of the LRA is revised to amend the program description, Enhancement 3, and Enhancement 4 as shown below:

B.2.1.18 Aboveground Metallic Tanks

Program Description

The Aboveground Metallic Tanks aging management program is an existing condition monitoring program which includes outdoor tanks sited on soil or concrete and indoor large volume tanks containing water with internal pressures approximating atmospheric pressure that are sited on concrete. The program will be enhanced to provide for management of loss of material and loss of sealing for metallic tanks within the scope of the program exposed to air–outdoor, concrete, condensation, soil, and treated water environments. The Unit 1 and Unit 2 cycled condensate storage tanks are the only tanks within the scope of this program. These tanks are fabricated from aluminum plates and are not coated or insulated. The aluminum alloy is not susceptible to cracking. The program includes caulking at the tank interface with the tank foundation as a preventive measure to mitigate corrosion. Visual inspections are performed to monitor degradation of the tank surfaces and caulking ***(caulking inspections are supplemented with physical manipulation)***. Visual inspections of interior tank surfaces are performed to detect loss of material. The bottoms of the tanks are examined volumetrically. These inspections and examinations ensure that significant degradation is not occurring and that the intended function of the cycled condensate storage tanks is maintained during the period of extended operation.

Enhancements

3. Perform a volumetric examination of the tank bottom for both cycled condensate storage tanks for signs of loss of material whenever the tanks are drained. At a minimum, an inspection shall be performed within 10 years prior to the period of extended operation and subsequent inspections shall be performed in each 10-year period during the period of extended operation. ***The next inspection scope will include 100% of the accessible areas of each of the tank bottoms that are within 30 inches of the shell. Included in this scope are the patch plates that are directly exposed to the sand bed below. Additionally, 10 random locations of approximately one square foot each, outside of the 30 inch band, will be inspected. This inspection program will encompass approximately 20% of the tank bottom and will inspect all the susceptible areas which were found during the baseline inspections. Based on the results of this inspection, the scope will be reassessed for future tank bottom inspections, per the Corrective Action Program.*** **Program Elements Affected: Parameters Monitored/Inspected (Element 3), Detection of Aging Effects (Element 4), Monitoring and Trending (Element 5)**

4. Perform an inspection of the caulking at the perimeter of the cycled condensate storage tank bases for signs of degradation each refueling interval ***(caulking inspections are supplemented with physical manipulation)***. **Program Elements Affected: Parameters Monitored/Inspected (Element 3), Detection of Aging Effects (Element 4) ~~Monitoring and Trending (Element 5)~~**

As a result of the responses to RAI B.2.1.13-3, RAI B.2.1.13-4, and RAI B.2.1.23-2 provided in Enclosure A of this letter, LRA Section 3.1.2.1.1, starting on page 3.1-2 of the LRA, is revised as follows:

3.1.2.1.1 Reactor Coolant Pressure Boundary System

Environments

The Reactor Coolant Pressure Boundary System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air with Reactor Coolant Leakage
- Closed Cycle Cooling Water
- ***Closed Cycle Cooling Water > 140 F***
- Lubricating Oil
- Reactor Coolant
- Steam
- Treated Water
- Treated Water > 140 F
- Waste Water

Aging Management Programs

The following aging management programs manage the aging effects for the Reactor Coolant Pressure Boundary System components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)
- BWR Stress Corrosion Cracking (B.2.1.7)
- Bolting Integrity (B.2.1.11)
- Closed Treated Water Systems (B.2.1.13)
- External Surfaces Monitoring of Mechanical Components (B.2.1.24)
- Flow-Accelerated Corrosion (B.2.1.10)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)
- Lubricating Oil Analysis (B.2.1.26)
- One-Time Inspection (B.2.1.21)
- ***Selective Leaching (B.2.1.22)***

- TLAA
- ***Unit 1*** One-time Inspection of ASME Code Class 1 Small-Bore Piping (B.2.1.23)
- ***Unit 2 Inspection of ASME Code Class 1 Small-Bore Piping Program (B.2.2.2)***
- Water Chemistry (B.2.1.2)

As a result of the response to RAI B.2.1.23-2 provided in Enclosure A of this letter, LRA Table 3.1-1, on page 3.1-25 of the LRA is revised as follows:

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-39	Steel, stainless steel, or steel with stainless steel cladding Class 1 piping, fittings and branch connections < NPS 4 exposed to reactor coolant	Cracking due to stress corrosion cracking, intergranular stress corrosion cracking (for stainless steel only), and thermal, mechanical, and vibratory loading	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components, Chapter XI.M2, "Water Chemistry," and XI.M35, "One-Time Inspection of ASME Code Class 1 Small-bore Piping"	No	Consistent with NUREG-1801 with exceptions. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) program, Water Chemistry (B.2.1.2) program, and ***Unit 1*** One-time Inspection of ASME Code Class 1 Small-Bore Piping (B.2.1.23) program will be used to manage cracking of the ***Unit 1*** carbon steel and stainless steel Class 1 piping, fittings, and branch connections < NPS 4 exposed to reactor coolant in the Reactor Coolant Pressure Boundary System. ***The Unit 2 Inspection of ASME Code Class 1 Small-Bore Piping Program (B.2.2.2) has been substituted for the One-time Inspection of ASME Code Class 1 Small-Bore Piping program and will be used with the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) program, and the Water Chemistry (B.2.1.2) program to manage cracking of the Unit 2 carbon steel and stainless steel Class 1 piping, fittings, and branch connections < NPS 4 exposed to reactor coolant in the Reactor Coolant Pressure Boundary System.*** An exception applies to the NUREG-1801 recommendations for Water Chemistry (B.2.1.2) program implementation.

As a result of the responses to RAI B.2.1.10-1, RAI B.2.1.13-3, RAI B.2.1.13-4, and RAI B.2.1.23-2 provided in Enclosure A of this letter, the affected pages of LRA Table 3.1.2-1, starting on page 3.1-44 of the LRA are revised as follows:

Table 3.1.2-1 Reactor Coolant Pressure Boundary System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Class 1 Piping, Fittings and Branch Connections < NPS 4" ***(Unit 1 only)***	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-40	A
			Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1.1-39	A
					Unit 1 One-time Inspection of ASME Code Class 1 Small-Bore Piping (B.2.1.23)	IV.C1.RP-230	3.1.1-39	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1.1-39	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-6	A, 3
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-39	3.1.1-31	E, 1
					Water Chemistry (B.2.1.2)	IV.C1.RP-39	3.1.1-31	D
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	IV.C1.R-23	3.1.1-60	***B***~~A~~
		Stainless Steel	Air - Indoor Uncontrolled (External)	None	None	IV.E.RP-04	3.1.1-107	A
			Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1.1-39	A
					Unit 1 One-time Inspection of ASME Code Class 1 Small-Bore Piping (B.2.1.23)	IV.C1.RP-230	3.1.1-39	A

Table 3.1.2-1 Reactor Coolant Pressure Boundary System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Class 1 Piping, Fittings and Branch Connections < NPS 4" ***(Unit 1 only)***	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1.1-39	B
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-6	A, 3
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-158	3.1.1-79	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-79	B
Class 1 Piping, Fittings and Branch Connections < NPS 4" (Unit 2 Only)	***Pressure Boundary***	***Carbon Steel***	***Air - Indoor Uncontrolled (External)***	***Loss of Material***	***External Surfaces Monitoring of Mechanical Components (B.2.1.24)***	***V.E.E-44***	***3.2.1-40***	***A***
			Reactor Coolant (Internal)	***Cracking***	***ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)***	***IV.C1.RP-230***	***3.1.1-39***	***A***
					Unit 2 Inspection of ASME Code Class 1 Small-Bore Piping Program (B.2.2.2)	***IV.C1.RP-230***	***3.1.1-39***	***E, 8***
					Water Chemistry (B.2.1.2)	***IV.C1.RP-230***	***3.1.1-39***	***B***
				Cumulative Fatigue Damage	***TLAA***	***IV.C1.R-220***	***3.1.1-6***	***A, 3***
				Loss of Material	***One-Time Inspection (B.2.1.21)***	***IV.C1.RP-39***	***3.1.1-31***	***E, 1***
					Water Chemistry (B.2.1.2)	***IV.C1.RP-39***	***3.1.1-31***	***D***
				Wall Thinning	***Flow-Accelerated Corrosion (B.2.1.10)***	***IV.C1.R-23***	***3.1.1-60***	***B***
		Stainless Steel	***Air - Indoor Uncontrolled (External)***	***None***	***None***	***IV.E.RP-04***	***3.1.1-107***	***A***
			Reactor Coolant (Internal)	***Cracking***	***ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)***	***IV.C1.RP-230***	***3.1.1-39***	***A***

Table 3.1.2-1 Reactor Coolant Pressure Boundary System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Class 1 Piping, Fittings and Branch Connections < NPS 4" (Unit 2 Only)	*Pressure Boundary*	*Stainless Steel*	*Reactor Coolant (Internal)*	*Cracking*	*Unit 2 Inspection of ASME Code Class 1 Small-Bore Piping Program (B.2.2.2)*	*IV.C1.RP-230*	*3.1.1-39*	*E, 8*
					Water Chemistry (B.2.1.2)	*IV.C1.RP-230*	*3.1.1-39*	*B*
				Cumulative Fatigue Damage	*TLAA*	*IV.C1.R-220*	*3.1.1-6*	*A, 3*
				Loss of Material	*One-Time Inspection (B.2.1.21)*	*IV.C1.RP-158*	*3.1.1-79*	*A*
					Water Chemistry (B.2.1.2)	*IV.C1.RP-158*	*3.1.1-79*	*B*

Table 3.1.2-1 Reactor Coolant Pressure Boundary System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Heat Exchanger - (Motor Winding Coolers) Tubes	Leakage Boundary	Copper Alloy with ~~less than 15% Zinc~~ ***15% Zinc or More***	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-57	C
			Closed Cycle Cooling Water (Internal)	***Cracking***	***Closed Treated Water Systems (B.2.1.13)***			***H, 6***
				Loss of Material	Closed Treated Water Systems (B.2.1.13)	V.D2.EP-97	3.2.1-32	C
					Selective Leaching (B.2.1.22)	***VII.C2.AP-43***	***3.3.1-72***	***C***
		Copper Alloy with less than 15% Zinc	***Closed Cycle Cooling Water (Internal)***	***Loss of Material***	***Closed Treated Water Systems (B.2.1.13)***	***V.D2.EP-97***	***3.2.1-32***	***C, 7***
Heat Exchanger - (Seal Coolers) Shell Side Components	***Leakage Boundary***	***Stainless Steel***	***Air - Indoor Uncontrolled (External)***	***None***	***None***	***IV.E.RP-04***	***3.1.1-107***	***C***
			Closed Cycle Cooling Water > 140 F (Internal)	***Cracking***	***Closed Treated Water Systems (B.2.1.13)***	***VII.E3.AP-192***	***3.3.1-44***	***A***
				Loss of Material	***Closed Treated Water Systems (B.2.1.13)***	***VII.C2.A-52***	***3.3.1-49***	***C***
Heat Exchanger - (Seal Coolers) Tube Side Components	***Pressure Boundary***	***Stainless Steel***	***Closed Cycle Cooling Water > 140 F (External)***	***Cracking***	***Closed Treated Water Systems (B.2.1.13)***	***VII.E3.AP-192***	***3.3.1-44***	***A***
				Loss of Material	***Closed Treated Water Systems (B.2.1.13)***	***VII.C2.A-52***	***3.3.1-49***	***C***
			Treated Water > 140 F (Internal)	***Cracking***	***One-Time Inspection (B.2.1.21)***	***VII.E3.AP-112***	***3.3.1-20***	***A***
					Water Chemistry (B.2.1.2)	***VII.E3.AP-112***	***3.3.1-20***	***B***
				Loss of Material	***One-Time Inspection (B.2.1.21)***	***V.D2.EP-73***	***3.2.1-17***	***C***
					Water Chemistry (B.2.1.2)	***V.D2.EP-73***	***3.2.1-17***	***D***

Table 3.1.2-1 Reactor Coolant Pressure Boundary System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Piping, piping components, and piping elements	Leakage Boundary	Aluminum Alloy	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.H2.AP-162	3.3.1-99	A
					One-Time Inspection (B.2.1.21)	VII.H2.AP-162	3.3.1-99	A
		Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-40	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-77	3.2.1-49	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-77	3.2.1-49	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-16	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-16	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-09	3.2.1-11	~~A~~***B***
			Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-91	A
		Copper Alloy with 15% Zinc or More	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-57	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-76	3.2.1-50	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-76	3.2.1-50	A
		Glass	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-14	3.3.1-117	A
			Lubricating Oil (Internal)	None	None	VII.J.AP-15	3.3.1-117	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	None	None	IV.E.RP-04	3.1.1-107	A

Table 3.1.2-1 Reactor Coolant Pressure Boundary System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Piping, piping components, and piping elements	Leakage Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D1.EP-80	3.2.1-50	A
					One-Time Inspection (B.2.1.21)	V.D1.EP-80	3.2.1-50	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-17	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	B
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-40	A
			Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-6	A, 3
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-39	3.1.1-31	E, 1
					Water Chemistry (B.2.1.2)	IV.C1.RP-39	3.1.1-31	D
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	IV.C1.R-23	3.1.1-60	~~A~~***B***
			Steam (Internal)	Cumulative Fatigue Damage	TLAA	VIII.B2.S-08	3.4.1-1	A, 3
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.B2.SP-160	3.4.1-14	A
					Water Chemistry (B.2.1.2)	VIII.B2.SP-160	3.4.1-14	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-07	3.2.1-11	~~A~~***B***
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	V.D2.E-10	3.2.1-1	A, 3
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-16	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-16	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-09	3.2.1-11	~~A~~***B***

Table 3.1.2-1 Reactor Coolant Pressure Boundary System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Tanks (EHC Reservoir)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-77	3.2.1-49	C
					One-Time Inspection (B.2.1.21)	V.D2.EP-77	3.2.1-49	C
Valve Body	Leakage Boundary	Aluminum Alloy	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-3	3.2.1-56	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.H2.AP-162	3.3.1-99	A
					One-Time Inspection (B.2.1.21)	VII.H2.AP-162	3.3.1-99	A
		Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-40	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-77	3.2.1-49	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-77	3.2.1-49	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-16	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-16	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-09	3.2.1-11	~~A~~***B***
		Copper Alloy with 15% Zinc or More	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-57	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D2.EP-76	3.2.1-50	A
					One-Time Inspection (B.2.1.21)	V.D2.EP-76	3.2.1-50	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	None	None	IV.E.RP-04	3.1.1-107	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D1.EP-80	3.2.1-50	A

Table 3.1.2-1 Reactor Coolant Pressure Boundary System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Valve Body	Leakage Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D1.EP-80	3.2.1-50	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-73	3.2.1-17	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	B
	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.24)	V.E.E-44	3.2.1-40	A
			Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-6	A, 3
				Loss of Material	One-Time Inspection (B.2.1.21)	IV.C1.RP-39	3.1.1-31	E, 1
					Water Chemistry (B.2.1.2)	IV.C1.RP-39	3.1.1-31	D
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	IV.C1.R-23	3.1.1-60	~~A~~***B***
			Steam (Internal)	Cumulative Fatigue Damage	TLAA	VIII.B2.S-08	3.4.1-1	A, 3
				Loss of Material	One-Time Inspection (B.2.1.21)	VIII.B2.SP-160	3.4.1-14	A
					Water Chemistry (B.2.1.2)	VIII.B2.SP-160	3.4.1-14	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-07	3.2.1-11	~~A~~***B***
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	V.D2.E-10	3.2.1-1	A, 3
				Loss of Material	One-Time Inspection (B.2.1.21)	V.D2.EP-60	3.2.1-16	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-16	B
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.10)	V.D2.E-09	3.2.1-11	~~A~~***B***
		Cast Austenitic Stainless Steel (CASS)	Air - Indoor Uncontrolled (External)	None	None	IV.E.RP-04	3.1.1-107	A

Table 3.1.2-1 Reactor Coolant Pressure Boundary System (Continued)

Notes	Definition of Note
A	Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.
B	Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.
C	Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.
D	Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.
E	Consistent with NUREG-1801 item for material, environment and aging effect, but a different aging management program is credited or NUREG-1801 identifies a plant-specific aging management program.
F	Material not in NUREG-1801 for this component.
G	Environment not in NUREG-1801 for this component and material.
H	Aging effect not in NUREG-1801 for this component, material and environment combination.
I	Aging effect in NUREG-1801 for this component, material and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-1801.

Plant Specific Notes:

1. The One-Time Inspection (B.2.1.21) program is substituted to manage the aging effects applicable to this component type, material and environment combination.
2. The ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD (B.2.1.1) program is substituted to manage the aging effects applicable to this component type, material and environment combination.
3. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.3.
4. The internal venturi section of each main steam line flow restrictor is fabricated from centrifugally cast low molybdenum content SA-351 Type CF8 CASS material. Therefore, these components are not susceptible to loss of fracture toughness due to thermal aging embrittlement.
5. The TLAA designation in the Aging Management Program column indicates that erosion of the main steam line flow restrictors is evaluated in Section 4.7.

6. The aging effects for copper alloy with 15% zinc or more in a closed cycle cooling water environment include cracking. The Closed Treated Water Systems (B.2.1.13) program is used to manage cracking for this component, material, and environment combination.

7. This component is a full-length sleeve inserted into certain existing heat exchanger tubes as a leak repair method; therefore there is no applicable external environment.

8. The plant-specific Unit 2 Inspection of ASME Code Class 1 Small-Bore Piping Program (B.2.2.2) is substituted to manage the aging effect(s) applicable to this component type, material and environment combination.

As a result of the response to RAI B.2.1.23-2 provided in Enclosure A of this letter, LRA Appendix A Updated Final Safety Analysis Report Supplement Table of Contents, starting on page A-1 of the LRA is revised as follows:

As a result of the response to RAI B.2.1.23-2 provided in Enclosure A of this letter, LRA Appendix A, Section A.1.1, NUREG-1801 Chapter XI Aging Management Programs, on page A-6 of the LRA is revised as follows:

23. ***Unit 1*** One-time Inspection of ASME Code Class 1 Small-Bore Piping
(Section A.2.1.23) [New]

As a result of the response to RAI B.2.1.23-2 provided in Enclosure A of this letter, LRA Appendix A, Section A.1.2, Plant-Specific Aging Management Programs, on page A-7 of the LRA is revised as follows:

1. Service Level III and Service Level III Augmented Coatings Monitoring and Maintenance Program (Section A.2.2.1) [New]

2. ***Unit 2 Inspection of ASME Code Class 1 Small-Bore Piping Program (Section A.2.2.2) [New]***

As a result of the responses to RAI B.2.1.23-1 and RAI B.2.1.23-2 provided in Enclosure A of this letter, LRA Appendix A, Section A.2.1.23 starting on page A-26 of the LRA is revised as follows:

A.2.1.23 ***Unit 1*** One-time Inspection of ASME Code Class 1 Small-Bore Piping

The ***Unit 1*** One-time Inspection of ASME Code Class 1 Small-Bore Piping aging management program is a new condition monitoring program that will manage the aging effect of cracking in ASME Code Class 1 small-bore piping that is less than nominal pipe size (NPS) 4-inches, and greater than or equal to NPS 1-inch. The program implements one-time inspection of a sample of piping full penetration (butt) and partial penetration (socket) welds that are susceptible to cracking using volumetric examinations. The inspection sample size will include at least 3 percent of the population of program butt welds with a maximum of 10 program butt welds~~ for each LSCS unit~~, and at least 3 percent of the population of program socket welds with a maximum of 10 program socket welds~~ for each LSCS unit~~. ***This results in 4 butt weld inspections and 10 socket weld inspections.*** Inspection of socket welds will be performed by a volumetric examination technique demonstrated to be capable of detecting cracking. If such a volumetric examination technique is not available by the time of the inspections, the examination method will be by destructive examination***. If destructive examination is used, then each weld receiving a destructive examination can be credited as equivalent to having volumetrically examined two welds.*** Inspections required by the program will augment ASME Code, Section XI requirements.

The only two instances of c~~C~~racking of ASME Code Class 1 small-bore piping ***at LSCS Unit 1*** ~~due to stress corrosion cracking, cyclical (including thermal, mechanical, and vibration fatigue) loading, thermal stratification or thermal turbulence~~ ***occurred during the first year of operation and were corrected by a design change*** ~~has not been experienced at LSCS Units 1 and 2~~. Therefore, this one-time inspection program is applicable and adequate to manage this aging effect during the period of extended operation. A plant-specific periodic inspection program will be implemented if evidence of cracking caused by IGSCC or fatigue is revealed in ASME Class 1 small-bore piping.

This new aging management program will be implemented prior to the period of extended operation. One-time inspections will be performed within the six years prior to entering the period of extended operation.

As a result of the responses to RAI B.2.1.23-1 and RAI B.2.1.23-2 provided in Enclosure A of this letter, Section A.2.2.2 is added to Appendix A at page A-43 as follows:

(This new section is not shown in Bold and Italicized print since it is all added)

A.2.2.2 Unit 2 Inspection of ASME Code Class 1 Small-Bore Piping Program

The Unit 2 Inspection of ASME Code Class 1 Small-Bore Piping Program is a new condition monitoring program that will manage the aging effect of cracking in ASME Code Class 1 small-bore piping that is less than nominal pipe size (NPS) 4-inches, and greater than or equal to NPS 1-inch. The program implements inspection of a sample of piping full penetration (butt) and partial penetration (socket) welds that are susceptible to cracking using volumetric or destructive examinations.

Unit 2 has experienced one failure of a Class 1 small-bore piping socket weld during its first 31 years of operation; therefore, a plant-specific aging management program is required. An extent of condition evaluation has identified other Unit 2 socket welds that may be susceptible to the age-related causal factors for that failure. Periodic inspections will be performed on those socket welds that are susceptible to the causal factors associated with the weld failure and one-time inspection will be performed on those welds that are not susceptible to those causes. Periodic inspections of 50 percent of the socket weld population that is susceptible to the causal factors associated with the failure (i.e., 5 welds) will be performed prior to the period of extended operation and every 10 years during the period of extended operation. One-time inspection will be performed on those welds that are not susceptible to the causal factors associated with the weld failure. The one-time inspection sample size will include at least 3 percent of the weld population or a maximum of 10 welds of each weld type (e.g. full penetration or socket weld). This results in one-time inspections of 3 butt welds and 10 socket welds.

Inspections required by the program will augment ASME Code, Section XI requirements. Inspection of socket welds will be performed by a volumetric examination technique demonstrated to be capable of detecting cracking or by destructive examination. If destructive examination is used, then each weld receiving a destructive examination can be credited as equivalent to having volumetrically examined two welds. The inspection of butt welds associated with Class 1 small-bore piping will be performed using volumetric examination techniques specified by ASME Code, Section XI. If any additional Class 1 small-bore welds fail or age-related cracking or degradation is identified by one-time or periodic inspection, the causes for the conditions will be evaluated using the corrective action program. The welds within systems that are susceptible to the causes associated with the condition will be included in the periodic inspection program.

This new aging management program will be implemented prior to the period of extended operation. The first sample of periodic inspections and the one-time inspections will be performed within the six years prior to entering the period of extended operation.

As a result of the response to RAI B.2.1.23-2 provided in Enclosure A of this letter, LRA Appendix B Aging Management Programs Table of Contents starting on page B-1 of the LRA is revised as follows:

As a result of the response to RAI B.2.1.23-2 provided in Enclosure A of this letter, LRA Appendix B, Section B.1.5, NUREG-1801 Chapter XI Aging Management Programs on page B-8 of the LRA is revised as follows:

23. ***Unit 1*** One-time Inspection of ASME Code Class 1 Small-Bore Piping (Section B.2.1.23) [New]

As a result of the response to RAI B.2.1.23-2 provided in Enclosure A of this letter, LRA Appendix B, Section B.1.6, Plant-Specific Aging Management Programs on page B-9 of the LRA is revised as follows:

1. Service Level III and Service Level III Augmented Coatings Monitoring and Maintenance Program (Section B.2.2.1) [New]

2. Unit 2 Inspection of ASME Code Class 1 Small-Bore Piping Program (Section B.2.2.2) [New]

As a result of the response to RAI B.2.1.23-2 provided in Enclosure A of this letter, LRA Appendix B, Section B.2.0, NUREG-1801 Aging Management Program Correlation on pages B-12 and B-13 of the LRA is revised as follows:

NUREG-1801 NUMBER	NUREG-1801 PROGRAM	LSCS PROGRAM
XI.M35	One-time Inspection of ASME Code Class 1 Small Bore-Piping	***Unit 1*** One-time Inspection of ASME Code Class 1 Small-Bore Piping (Section B.2.1.23)

NUREG-1801 NUMBER	NUREG-1801 PROGRAM	LSCS PROGRAM
N/A	LaSalle Plant-Specific Program	Service Level III and Service Level III Augmented Coatings Monitoring and Maintenance Program (B.2.2.1)
N/A	***LaSalle Plant-Specific Program***	***Unit 2 Inspection of ASME Code Class 1 Small-Bore Piping Program (Section B.2.2.2)***

As a result of the response to RAI B.2.1.23-2 provided in Enclosure A of this letter, LRA Appendix B, Section B.2.1.1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD on page B-15 of the LRA is revised as follows:

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. Any deviation from ASME Code, Section XI requirements must be approved by the NRC per a relief request.

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program includes all component inspection activity required by ASME Code, Section XI, Subsections IWB, IWC, and IWD except for those components that are covered by the following license renewal aging management programs that include augmented requirements:

- Reactor Head Closure Stud Bolting (B.2.1.3)
- BWR Vessel ID Attachment Welds (B.2.1.4)
- BWR Feedwater Nozzle (B.2.1.5)
- BWR Control Rod Drive Return Line Nozzle (B.2.1.6)
- BWR Stress Corrosion Cracking (B.2.1.7)
- BWR Penetrations (B.2.1.8)
- BWR Vessel Internals (B.2.1.9)
- ***Unit 1*** One-time Inspection of ASME Code Class 1 Small-Bore Piping (B.2.1.23)
- ***Unit 2 Inspection of ASME Code Class 1 Small-Bore Piping Program (B.2.2.2)***

As a result of the responses to RAI B.2.1.23-1 and RAI B.2.1.23-2 provided in Enclosure A of this letter, LRA Appendix B, Section B.2.1.23 starting on page B-102 of the LRA is revised as follows:

B.2.1.23 *Unit 1* One-time Inspection of ASME Code Class 1 Small-Bore Piping

Program Description

The ***Unit 1*** One-time Inspection of ASME Code Class 1 Small-Bore Piping aging management program is a new conditioning monitoring program that will manage cracking of piping in a reactor coolant environment. The program will perform one-time inspection of a sample of ASME Code Class 1 piping less than nominal pipe size (NPS) 4-inches and greater than or equal to NPS 1-inch. The program includes pipes, fittings, branch connections, and full penetration (butt) welds and partial penetration (socket) welds. ***The only two instances of*** ~~C~~***c***racking of ASME Code Class 1 small-bore piping ***at LSCS Unit 1*** ~~due to stress corrosion cracking, cyclical (including thermal, mechanical, and vibration fatigue) loading, thermal stratification or thermal turbulence~~ ***occurred during the first year of operation and were corrected by a design change***~~has not been experienced at LSCS Units 1 and 2~~. Therefore, this one-time inspection program is applicable and adequate to manage this aging effect during the period of extended operation. Program inspections will augment ASME Code, Section XI requirements.

For the current third 10-year interval, the ISI program applies the requirements of ASME Code, Section XI, 2001 Edition through 2003 Addenda, and Risk Informed Inservice Inspection (RISI) alternative requirements to Examination Categories for Class 1 welds as approved by relief request. Any deviation from ASME Code, Section XI requirements must be approved by the NRC per a relief request. The current ISI program for the third 10-year interval includes periodic volumetric ultrasonic testing of selected Class 1 small-bore piping butt welds. The ***Unit 1*** One-time Inspection of ASME Code Class 1 Small-Bore Piping program will also include inspection of socket welds using a volumetric examination technique demonstrated to be capable of detecting cracking. If such a volumetric examination technique is not available by the time of the inspections, the examination method will be by destructive examination. If destructive examinations are performed, each examination will be credited as equivalent to two volumetrically examined socket welds.

Unit~~s~~ 1 ~~and 2~~ ha~~ve~~***s*** been operating for more than 32 years ***since the design change was implemented to correct the condition that caused two socket weld failures during the first year of operation*** ~~and 31 years respectively, at the time of the license renewal application submittal,~~ ~~and have~~***s*** ~~not~~ ***without*** experienc~~ed~~i***ng*** cracking of ASME Code Class 1 small-bore piping due to stress corrosion, cyclical (including thermal, mechanical, and vibration fatigue) loading, or thermal stratification and thermal turbulence. The inspection sample size will include at least 3 percent of the population of program butt welds with a maximum of 10 program butt welds ~~for each LSCS unit,~~ and at least 3 percent of the population of program socket welds with a maximum of 10 program socket welds ~~for each LSCS unit~~. This methodology results in ~~1~~***4*** butt weld***s*** ~~on each unit,~~ and 10 socket welds ~~on each unit~~ selected for one-time inspection. This ensures an adequate sample size to provide confidence that the

aging effect of cracking is not an issue at LSCS ***Unit 1***. Sample locations will be selected based on susceptibility for cracking due to stress corrosion cracking and fatigue, consequence of failure, inspectability, dose considerations, operating experience, and limiting locations of the total population of ASME Code Class 1 small-bore piping locations.

The program includes controls to implement an alternate plant-specific periodic inspection aging management program should evidence of ASME Class 1 small-bore piping cracking caused by intergranular stress corrosion cracking (IGSCC) or fatigue be revealed by review of LSCS ***Unit 1*** operating experience prior to the period of extended operation, or by the examinations performed as part of this program.

The program also includes controls to direct that if ASME Class 1 small-bore piping in a particular plant system experiences cracking, small-bore piping in all Class 1 plant systems shall be evaluated to determine whether the cause for the cracking affects those other systems.

The new ***Unit 1*** One-time Inspection of ASME Code Class 1 Small-Bore Piping program will be implemented prior to the period of extended operation. One-time inspections will be performed within the six years prior to entering the period of extended operation.

NUREG-1801 Consistency

The ***Unit 1*** One-time Inspection of ASME Code Class 1 Small-Bore Piping aging management program will be consistent with the ten elements of aging management program XI.M35, "One-time Inspection of ASME Code Class 1 Small-Bore Piping", specified in NUREG-1801.

Exceptions to NUREG-1801

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the ***Unit 1*** One-time Inspection of ASME Code Class 1 Small-Bore Piping program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the period of extended operation:

1. An extensive review of plant operating experience was performed to determine if Unit~~s~~ 1 ~~or 2~~ ha~~ve~~***s*** experienced cracking of ASME Code Class 1 small-bore piping caused by IGSCC or fatigue during ~~their~~ ***its*** operating history. The review included a key word search of the corrective action program database going back to January 2001, a review of correspondence to the NRC going back to 1982, and interviews with the LSCS ISI program owner for input as to whether cracking of Class 1 small-bore piping had occurred. The review did not identify any issues where cracking of ASME Code Class 1 small-bore piping caused by ***age-related*** IGSCC or fatigue occurred during the ***Unit 1*** operating history. The review identified two ~~issues with~~ ***Class 1 small-bore piping socket*** weld~~s~~ ***failures*** ~~during startup~~ in ***February*** 1983, ~~one preservice plugs-type weld issue in 1986, and a pinhole leak identified in a socket weld in 2005.~~ ***after less than nine months of intermittent plant operation, and two leaks from seal welds applied to threaded pre-service plugs in Class 1 residual heat removal system piping, identified in 1986***. ~~The pinhole leak was between the body of the a valve and a drain line of the main steam system, and the cause evaluation concluded that the pinhole leak was caused by a weld inclusion or defect due to porosity following repairs performed in 1995, and not cracking.~~

The two socket weld failures in 1983 were at the 2-inch drain connections to 26-inch main steam isolation valves. The causes were determined to be improper weld application and installation, most likely related to less than optimum pre-heat treatment and welding electrodes. Corrective actions included implementation of a design change that re-welded the socket weld connections to all the main steam isolation valves on LSCS Units 1 and 2 using an improved welding procedure. Also, the Unit 1 drain lines were instrumented to verify that no abnormal vibration amplitudes or frequencies existed. Since these failures occurred after less than nine months of operation, they were not age-related. The corrective actions and design change have been proven effective as indicated by more than 32 years of operation with no further indications of degradation,

The seal weld failures identified in 1986 were associated with ¾-inch threaded plugs, and are therefore not small-bore socket welds or butt welds that are within the scope of this program.

This example provides objective evidence that the measures in place to prevent cracking of ASME Code Class 1 small-bore piping caused by IGSCC and fatigue, including the design of the plant piping systems to prevent cracking caused by fatigue and effective water chemistry controls to prevent IGSCC, have been effective.

2. Periodic volumetric examinations of ASME Code Class 1 small-bore piping butt welds and visual external surface examinations of ASME Code Class 1 small-bore piping socket welds have been performed in accordance with the Risk Informed ISI program since 2002 on Unit 1~~, and 2003 on Unit 2~~ with no unacceptable examination results. Prior to 2002, ASME Code Class 1 small-bore piping butt welds and socket welds received periodic visual external surface examination per ASME Code, Section XI, Table IWB-2500-1 Examination Category B-J, Item Nos. B9.21, ***B9.32,*** and B9.40. With the exception of the pinhole leak***s*** identified in ***two in-scope***~~a~~ Class 1 socket weld***s***, described in OE example 1, there were no unacceptable examination results.

This example provides objective evidence that the measures in place to prevent cracking of ASME Code Class 1 small-bore piping caused by IGSCC and fatigue, including the design of the plant piping systems to prevent cracking caused by fatigue and ~~effective~~ water chemistry controls to prevent IGSCC, have been effective.

3. In 1986, two welds on Unit 1, that were later ***included*** within the scope of NRC GL 88-01, had flaws identified using volumetric examination. In 1990, the crowns on these welds were machined, and subsequent volumetric examination characterized these as root geometry indications, not IGSCC cracks. There are currently no welds within the ***Unit 1*** ASME Code Class 1 boundary that have cracks.

This example illustrates how implementation of volumetric examination was applied to identify minor indications that could be indicative of cracks in piping welds.

The operating experience relative to the new ***Unit 1*** One-time Inspection of ASME Code Class 1 Small-Bore Piping program did not identify an adverse trend in performance. A review of LSCS ***Unit 1*** specific operating experience and ISI inspections performed per ASME Section XI and the current ISI program indicates that cracking of ASME Code Class 1 small-bore piping caused by IGSCC or fatigue has not occurred. The inspection methods being implemented by the existing ISI program have been proven effective in detecting cracking. The expanded scope of inspection and improved inspection methods implemented by the new ***Unit 1*** One-time Inspection of ASME Code Class 1 Small-Bore Piping program will further improve the effectiveness of the ISI program to manage the aging effect of cracking. Appropriate guidance for re-evaluation, repair, or replacement is provided for locations where degradation is found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that the implementation of the ***Unit 1*** One-time Inspection of ASME Code Class 1 Small-Bore Piping program will effectively identify cracking prior to loss of intended function during the period of extended operation.

Conclusion

The new ***Unit 1*** One-time Inspection of ASME Code Class 1 Small-Bore Piping program will provide reasonable assurance that the aging effect of cracking will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the period of extended operation.

As a result of the responses to RAI B.2.1.23-1 and RAI B.2.1.23-2 provided in Enclosure A of this letter, Section B.2.2.2 is added to LRA Appendix B at page B-181 as follows:

(This new section is not shown in Bold and Italicized print since it is all added)

B.2.2.2 Unit 2 Inspection of ASME Code Class 1 Small-Bore Piping Program

Program Description

The Unit 2 Inspection of ASME Code Class 1 Small-Bore Piping Program is a new plant-specific condition monitoring program that is relevant to plants that have experienced cracking in ASME Code Class 1 small-bore piping welds. The program will perform inspection activities of a sample of ASME Code Class 1 piping less than nominal pipe size (NPS) 4-inches and greater than or equal to NPS 1-inch to detect cracking that may be caused by stress corrosion cracking, cyclical (including thermal, mechanical, and vibration fatigue) loading, or thermal stratification or thermal turbulence. The program includes inspections prior to and during the period of extended operation that will augment the requirements in ASME Code, Section XI. The program will include pipes, fittings, branch connections, and full penetration (butt) and partial penetration (socket) welds exposed to a reactor coolant environment. This program includes guidance within NUREG-1801 (GALL) Chapter XI, AMP XI.M35, "One-time Inspection of ASME Code Class 1 Small-Bore Piping."

Unit 2 experienced a socket weld failure in 2005 where the 2-inch main steam drain piping is connected to the 'D" outboard main steam isolation valve (MSIV) body. Since it has not been demonstrated that this failure has been effectively mitigated, this plant-specific program is being implemented for Unit 2 ASME Code Class 1 small-bore piping welds, consistent with GALL Chapter XI, AMP XI.M35.

As discussed in GALL Chapter XI, AMP XI.M35, "for systems that have experienced cracking and operating experience indicates that design changes have not been implemented to effectively mitigate cracking, periodic inspection is proposed, as managed by a plant-specific AMP." Additionally, GALL Report AMP XI.M35 states, "If small-bore piping in a particular plant system has experienced cracking, small-bore piping in all plant systems are evaluated to determine whether the cause for the cracking affects other systems (corrective action program)." Risk significance is considered in determining the frequency of inspection and the sample size of welds that will be inspected. This new program includes evaluation of all Unit 2 systems that include ASME Code Class 1 small-bore piping to determine whether the causes of the socket weld failure identified in 2005 affect other systems. For those systems where the evaluation concludes that the cause of the prior failure may affect additional welds, those susceptible Class 1 small-bore piping welds are included in a population that will be inspected periodically, including inspection prior to and during the period of extended operation. The frequency of inspection and sample size that will be inspected is based on evaluation of system and weld characteristics, including weld design, materials, environment, piping configuration, and fluid flow service.

For those systems and welds where the evaluation concludes that the cause of the prior failure does not affect them, those welds are included in a population that will be inspected via a one-time inspection prior to the period of extended operation, consistent with the guidance in GALL Chapter XI, AMP XI.M35.

Inspection of socket welds will be performed by a volumetric examination technique demonstrated to be capable of detecting cracking or by destructive examination. If destructive examination is used, then each weld receiving a destructive examination can be credited as equivalent to having volumetrically examined two welds. Destructive examination has proven effective in identifying cracking and determining the root cause of cracks and other failures in small-bore piping. The inspection of butt welds associated with Class 1 small-bore piping will be performed using volumetric examination techniques specified by ASME Code, Section XI.

This new program will be implemented prior to the period of extended operation. The first sample of periodic inspections and the one-time inspections will be performed within the six years prior to entering the period of extended operation. If additional Class 1 small-bore piping welds experience age-related failure, or cracking is identified by inspection, all Unit 2 systems that include ASME Code Class 1 small-bore piping will be evaluated to determine whether the causes of the failure affects other systems. For those systems where the evaluation concludes that the cause of the failures affects additional welds, those susceptible Class 1 small-bore piping welds will be included in a population that will be inspected periodically. The frequency of inspection and sample size that will be inspected will be based on evaluation of system and weld characteristics, including weld design, materials, environment, piping configuration, and fluid flow service.

Aging Management Elements

The results of an evaluation of each program element against the 10 elements described in Appendix A of the Standard Review Plan of License Renewal Applications for Nuclear Power Plants, NUREG-1800, are provided below.

Scope of Program – Element 1

The new Unit 2 Inspection of ASME Code Class 1 Small-Bore Piping Program includes ASME Code Class 1 piping less than NPS 4-inches and greater than or equal to NPS 1-inch. The program scope includes pipes, fittings, branch connections, and full penetration (butt) and partial penetration (socket) welds within the Unit 2 Reactor Coolant Pressure Boundary license renewal system that are exposed to a reactor coolant environment. The license renewal Reactor Coolant Pressure Boundary system includes ASME Code Class 1 small-bore piping within the following plant systems:

- Feedwater (FW)
- Main Steam (MS)
- Nuclear Boiler (NB)

- Reactor Core Isolation Cooling (RI)
- Reactor Recirculation (RR)
- Reactor Water Cleanup (RT)
- Residual Heat Removal (RH)
- Standby Liquid Control (SC)

Preventive Actions – Element 2

The new Unit 2 Inspection of ASME Code Class 1 Small-Bore Piping Program is a condition monitoring program that includes inspection activities intended to detect degradation of components before loss of intended function. The program is independent of methods to mitigate or prevent degradation, and therefore does not include preventive actions.

The program validates the effectiveness of the Water Chemistry (B.2.1.2) aging management program to prevent and mitigate IGSCC for ASME Code Class 1 small-bore piping components that are susceptible to cracking due to IGSCC. The program also validates the adequacy of the design of ASME Code Class 1 small-bore piping systems to minimize the probability of cracking due to cyclic (including thermal, mechanical, and vibration fatigue) loading or thermal stratification and thermal turbulence.

Parameters Monitored/Inspected – Element 3

The new Unit 2 Inspection of ASME Code Class 1 Small-Bore Piping Program includes inspection activities to detect cracking that may be caused by stress corrosion cracking, cyclical (including thermal, mechanical, and vibration fatigue) loading, or thermal stratification or thermal turbulence. The inspection samples will include both butt welds and socket welds.

The inspection of butt welds associated with Class 1 small-bore piping will be performed using volumetric examination techniques specified by ASME Code, Section XI, which have been proven effective in identifying cracks, and are currently in use for piping examinations. Inspection of socket welds will be performed by volumetric examination technique demonstrated to be capable of detecting cracking, or by destructive examination.

This new program is a condition monitoring program that does not include performance monitoring, preventive, or mitigating elements or actions.

Detection of Aging – Element 4

The new Unit 2 Inspection of ASME Code Class 1 Small-Bore Piping Program will perform inspection activities to detect cracking. The program will augment ASME Section XI, Inservice Inspection, Subsection IWB inspection requirements for Class 1

small-bore piping welds to include volumetric or destructive examinations that will detect cracking degradation prior to loss of function. The inspection of butt welds associated with Class 1 small-bore piping will be performed using volumetric examination techniques specified by ASME Code, Section XI. Volumetric examinations of small-bore socket welds will be performed using demonstrated techniques that are capable of detecting the aging effects (cracking) in the examination volume of interest, or by destructive examination techniques that have been proven effective in identifying cracking and determining the root cause of cracks and other failures in small-bore piping. Because more information can be obtained from a destructive examination, than from a volumetric examination, each weld receiving a destructive examination can be credited as equivalent to having volumetrically examined two welds.

Unit 2 has been operating for more than 31 years, and has experienced one failure of an ASME Code Class 1 small-bore piping weld. See Element 10 for discussion of a pinhole leak identified in a Class 1 socket weld that connects a small-bore drain line to the body of a main steam isolation valve (MSIV) in the plant main steam system, identified in 2005. The cause evaluation, performed in 2005, concluded that the pinhole leak was caused by a weld inclusion or defect due to porosity following weld repairs performed in 1995. A subsequent evaluation has concluded that the failure had age-related causal factors that resulted in a pre-existing flaw in the weld to propagate to a leak. Consistent with GALL Chapter XI, AMP XI.M35, Program Description, an evaluation was performed for all Unit 2 plant systems that include ASME Code Class 1 small-bore piping to determine whether the age-related causal factors for the weld failure affects other systems that include Class 1 small-bore piping welds. This evaluation identified a population of 10 Unit 2 Class 1 small-bore piping socket welds that may be susceptible to the causal factors associated with the Class 1 socket weld failure identified in 2005. This population of welds will be subject to periodic inspection. Fifty percent of this population of welds (i.e., 5 welds) will be inspected in the six-year period prior to the period of extended operation and every 10 years during the period of extended operation. Since only one small-bore socket weld has failed in the 31-year Unit 2 operating history, and that failure was at the only reworked weld within the population of welds that may be susceptible to the causal factors associated with the failure, inspection of 50 percent of the population prior to the period of extended operation and every 10 years during the period of extended operation is considered appropriate.

This program also includes one-time inspection using volumetric or destructive techniques for Class 1 small-bore piping welds determined to be not susceptible to the causal factors associated with the weld failure identified in 2005. The one-time inspections will be completed within the six-year period prior to the period of extended operation. At least 3 percent of the weld population or a maximum of 10 welds of each weld type (e.g. full penetration or socket weld) will be selected for one-time inspection. Since there are approximately 448 socket welds and 94 butt welds in this population, a minimum of 10 socket welds and 3 butt welds will be inspected. GALL Chapter XI, AMP XI.M35 recommends a one-time inspection sample size of at least 3 percent or a maximum of 10 welds for each weld type for plants that have never experienced a Class 1 small-bore piping failure, and have an extensive operating history of more than 30 years. Unit 2 has had a small-bore piping failure, and that weld and other welds

that may be affected by age-related causal factors for that weld failure, are subject to periodic inspection as described above. The welds within the one-time inspection population are not susceptible to the causal factors associated with the only small-bore piping failure experienced at LSCS Unit 2 over its 31-year operating history. Therefore, a sample size of at least 3 percent or a maximum of 10 welds for each weld type is considered appropriate for the population of welds subject to one-time inspection.

Consistent with GALL Chapter XI, AMP XI.M35, Element 4, the welds that are most susceptible to aging mechanisms and those that are most risk-significant will be selected for inspection. Also to be considered in selecting the welds for inspection are inspectability, dose considerations, operating experience, and locations with limiting conditions within the total population of welds.

In summary, consistent with GALL Chapter XI, AMP XI.M35, Program Description, for systems that have experienced cracking (age-related failure), periodic inspection is implemented using a plant-specific AMP. This new plant-specific program includes periodic volumetric or destructive inspections prior to and during the period of extended operation for the population of welds determined to be susceptible to the causal factors associated with the weld failure. This program also includes one-time inspection prior to the period of extended operation for the population of Class 1 small-bore piping welds that are not susceptible to the causal factors associated with the weld failure. These inspections are considered appropriate to ensure that component intended function(s) will be adequately maintained for license renewal under all current licensing basis (CLB) design conditions.

If any additional Class 1 small-bore welds fail or age-related cracking or degradation is identified by one-time or periodic inspection, the causes for the conditions will be evaluated using the corrective action program. Consistent with guidance in GALL Chapter XI, AMP XI.M35, an evaluation will be performed to determine whether the cause of the condition affects other systems that include Class 1 small-bore piping. The welds within systems that are susceptible to the causes associated with the condition will be subjected to periodic inspection.

This new program is a condition monitoring program that does not include performance monitoring, preventive, or mitigating elements or actions.

Monitoring and Trending – Element 5

The new Unit 2 Inspection of ASME Code Class 1 Small-Bore Piping Program includes inspection activities to detect cracking that may be caused by stress corrosion cracking, cyclical (including thermal, mechanical, and vibration fatigue) loading or thermal stratification or thermal turbulence. This program does not involve actions to trend or monitor the rate of age-related degradation. If any indication of age-related degradation or cracking is identified, then ASME Code, Section XI will be applied to determine the acceptability of the condition, and any required corrective actions, as discussed in Element 6.

Plant-specific operating experience relative to Class 1 small-bore piping material condition will be used to determine if the population of welds requiring periodic inspection should be increased. If a Class 1 small-bore piping weld fails or age-related cracking or degradation is identified by one-time or periodic inspection, then the causes for the condition will be evaluated using the corrective action program. Also, consistent with guidance in GALL Chapter XI, AMP XI.M35, use of the corrective action program will result in an evaluation being performed to determine whether the cause of the condition affects other systems that include Class 1 small-bore piping. The welds within systems that are susceptible to the causes associated with the condition will be included in the population of welds subjected to periodic inspection.

Similarly, industry operating experience will continue to be reviewed in accordance with the LSCS operating experience program. Leakage or cracking of Class 1 small-bore piping identified at other nuclear plants will be reviewed for applicability to this program.

Acceptance Criteria – Element 6

The LSCS ASME Code Section XI Inservice Inspection (ISI) program directs that inspection results, including indications of cracking are evaluated in accordance with the ASME Code, Section XI, IWA-3000, against applicable acceptance standard criteria that are specified in the ASME Code, Section XI, IWB-3000 for Class 1 components. All components within the new Unit 2 Inspection of ASME Code Class 1 Small-Bore Piping Program are ASME Code, Class 1. The current ISI Program is based on EPRI TR-112657, “Revised Risk Informed Inservice Inspection Evaluation Procedure,” Revision B-A, ASME Code Case N-578-1, and associated industry documents.

The acceptance criteria for examinations of Class 1 small-bore piping butt welds will be per ASME Code, Section XI, Paragraphs IWB-3400 and IWB-3500; flaws or indications will be evaluated per IWB-3131; and additional examinations will be performed per IWB-2430, as supplemented by the appropriate sections of Code Cases N-578-1 and N-586-1. Evaluation of flaws identified during a volumetric examination of socket welds will be in accordance with IWB-3600 methods.

Corrective Actions – Element 7

All components within the new Unit 2 Inspection of ASME Code Class 1 Small-Bore Piping Program are ASME Code, Class 1, safety-related components. The new Unit 2 Inspection of ASME Code Class 1 Small-Bore Piping Program is controlled as an augmented program under the administrative control of the ISI program. Administrative procedures that control the ISI program direct that when a flaw exceeds the applicable acceptance standards of IWB-3400 or IWB-3500 a corrective action report is initiated in accordance with the corrective action program. The LSCS 10 CFR Part 50, Appendix B corrective action program ensures that conditions adverse to quality are promptly corrected. If the deficiency is assessed to be adverse to quality, the cause of the condition is determined and an action plan is developed to preclude recurrence.

Confirmation Process – Element 8

Site quality assurance procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of the 10 CFR Part 50, Appendix B Quality Assurance Program. The corrective action program requires that when corrective actions are necessary, there are follow-up activities to confirm that the corrective actions have been completed and that the corrective actions have been effective.

Administrative Controls – Element 9

The Unit 2 Inspection of ASME Code Class 1 Small-Bore Piping Program is a new condition monitoring program developed for license renewal. As required, the FSAR supplement includes a summary description of the program and activities for managing the effects of aging for license renewal.

Site quality assurance procedures, review and approval processes, and administrative controls are implemented for program activities in accordance with the requirements of the LSCS 10 CFR Part 50, Appendix B Quality Assurance Program.

Operating Experience – Element 10

The following examples of operating experience provide objective evidence that the Unit 2 Inspection of ASME Code Class 1 Small-Bore Piping Program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the period of extended operation:

1. An extensive review of plant operating experience was performed to determine if Unit 2 experienced cracking of ASME Code Class 1 small-bore piping caused by IGSCC or fatigue during its operating history. The review included a key word search of the corrective action program database going back to January 2001, a review of correspondence to the NRC going back to 1982, and interviews with the LSCS ISI program owner for input as to whether cracking of Class 1 small-bore piping had occurred. The review identified only one issue where a Unit 2 ASME Code Class 1 small-bore piping weld failed. The issue involved a pinhole leak identified in 2005 by VT-2 inspection during a reactor coolant pressure boundary leak test on the 2-inch main steam system drain line that connects to the body of the "D" outboard main steam isolation valve. The pinhole leak was in the socket weld where the 2-inch line connects to the body of the valve.

The cause of the failure was determined to be a weld inclusion or defect originating from a weld repair performed in April 1995. In 1995, the 2-inch drain line, including the socket weld to the valve, was replaced due to a minimum wall condition on the piping that was caused by excessive grinding on the outside piping surface, away from the weld. It was concluded that the pinhole flaw was due to porosity in the weld repair made in 1995, and that the flaw likely developed below the surface. It is likely that operational stresses and/or mechanical stress risers due to the local curvature of the valve played a role in propagating the flaw.

Although the cause evaluation documented in 2005 concluded that the cause of the failure was a defect in the weld made in 1995, it is now concluded that the weld failure identified in 2005 had contributing causes that were related to aging mechanisms.

This example provides objective evidence that the measures in place to prevent cracking of ASME Code Class 1 small-bore piping caused by IGSCC and fatigue, including the design of the plant piping systems to prevent cracking caused by fatigue and effective water chemistry controls to prevent IGSCC, and corrective actions associated with adverse conditions have been effective.

2. Periodic volumetric examinations (UT) of ASME Code Class 1 small-bore piping butt welds and visual examinations of ASME Code Class 1 small-bore piping socket welds have been performed in accordance with the Risk Informed ISI program since 2002 on Unit 1, and 2003 on Unit 2, with no unacceptable examination results. In 2005, four 3-inch butt welds on the Unit 2 main steam drain piping were inspected by UT with no recordable indications. Prior to 2002, ASME Code Class 1 small-bore piping butt welds and socket welds received periodic visual external surface examination per ASME Code, Section XI, Table IWB-2500-1 Examination Category B-J. With the exception of the pinhole leak identified in a Class 1 socket weld, described in OE example 1, there have been no unacceptable examination results.

This example provides objective evidence that the measures in place to identify cracking of ASME Code Class 1 small-bore piping caused by IGSCC and fatigue, including inspections required by ASME Section XI, Subsection IWB, have been utilized effectively.

The operating experience relative to the Unit 2 Inspection of ASME Code Class 1 Small-Bore Piping Program did not identify an adverse trend in performance. The inspection methods being implemented by the program have proven effective in detecting cracking. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. The program will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the Unit 2 Inspection of ASME Code Class 1 Small-Bore Piping Program will effectively identify degradation prior to failure or loss of intended function during the period of extended operation.

NUREG-1800 Consistency

The Unit 2 Inspection of ASME Code Class 1 Small-Bore Piping Program will be consistent with the ten elements of an aging management program described in NUREG-1800.

Exceptions to NUREG-1800

None.

Enhancements

None.

Conclusion

The new Unit 2 Inspection of ASME Code Class 1 Small-Bore Piping Program will provide reasonable assurance that the aging effect of cracking will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the period of extended operation.

As a result of the response to RAI 4.1-3 provided in Enclosure A of this letter, LRA Section 4.1.5 on LRA page 4-4 is revised as follows:

4.1.5 IDENTIFICATION OF EXEMPTIONS PURSUANT TO 10 CFR 50.12

~~Exemptions currently in effect for LaSalle Unit 1 and Unit 2 pursuant to 10 CFR 50.12 were reviewed and it was determined that none were associated with or supported by TLAAs. Therefore, no further evaluation is required.~~

10 CFR 54.21(c)(2) states: A list must be provided of plant-specific exemptions granted pursuant to 10 CFR 50.12 and in effect that are based on time-limited aging analyses as defined in 10 CFR 54.3. The applicant shall provide an evaluation that justifies the continuation of these exemptions for the period of extended operation.

A search of docketed correspondence, the operating license, the Updated Final Safety Analysis Report (UFSAR), and Safety Evaluation Report identified one exemption in effect that is based upon a time-limited aging analysis. This exemption is shown in LRA Table 4.1-3 and is associated with Pressure-Temperature (P-T) limits developed using procedures based on an exemption to 10 CFR 50 Appendix G.

As a result of the response to RAI 4.1-3 provided in Enclosure A of this letter, LRA Table 4.1-3 is added as LRA pages 4-6a and 4-6b, as follows:

(This new table is not shown in Bold and Italicized print since it is all added)

Table 4.1-3 – LSCS EXEMPTION EVALUATION TABLE

Exemption Approval Date	Exemption Description	Based upon TLAA?	In Effect during PEO?
LSCS Unit 1 and Unit 2 11/8/2000	By letter dated November 8, 2000, in accordance with 10 CFR 50.12, the staff granted an exemption to the requirements of 10 CFR 50, Appendix G for LaSalle Unit 1 and Unit 2, that permits the use of American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code, Code Case N-640, "Alternative Requirement Fracture Toughness for Development of P-T Limit Curves for ASME B&PV Code Section XI, Division 1," in calculating RPV P-T limits. The methodology that was used to recalculate the RPV P-T limits submitted in the license amendment request dated February 29, 2000 was based on the ASME Code Case N-640 cited above. Therefore, the P-T limits approved by the November 8, 2000 SER are based upon a TLAA and require evaluation for the period of extended operation.	Yes	No. See Notes 1 and 2

Notes:

(1) The license amendment request associated with this exemption, dated February 29, 2000, as supplemented on June 26 and August 18, 2000, requested exemption to 10 CFR 50 Appendix G to permit the use of ASME Code Cases N-588 and N-640. In the SER dated November 8, 2000, the staff determined that Code Case N-588 is not relevant to the evaluation of the LaSalle Unit 1 or Unit 2 RPVs because neither of the LaSalle RPVs is limited in the beltline region by a circumferential weld. Therefore, Code Case N-588 does not affect the evaluation of the beltline region for the LaSalle Unit 1 RPV, which is limited by an axial weld, nor does it affect the LaSalle Unit 2 RPV, which is limited by the lower intermediate shell plate material. Therefore, the staff determined that an exemption to use Code Case N-588 was not necessary for LaSalle Unit 1 and Unit 2. The exemption that was granted only applies to ASME Code Case N-640.

(2) This exemption to 10 CFR 50, Appendix G will not need to be continued into the period of extended operation for LaSalle Unit 1 or Unit 2. The 2004 Edition of the ASME Code introduced a more recent version of Appendix G to Section XI of the ASME Code than the version in effect when this exemption was approved that incorporates the provisions of ASME Code Case N-640. The 2004 Edition has been endorsed in 10 CFR 50.55a, and therefore, by reference in 10 CFR Part 50, Appendix G.

The pressure-temperature (P-T) limits that were submitted for approval on February 29, 2000 that were based upon the exemption have been superseded by P-T limits that were prepared in accordance with the 2004 or later Editions of the ASME Code that incorporated Code Case N-640. The current Unit 1 P-T limits were approved by the NRC on November 25, 2014 in Amendment No. 210 to License No. NPF-11. The current Unit 2 P-T limits were approved by the NRC in on April 15, 2011 in Amendment 188 to License No. NPF-18.

Therefore, since the current P-T limits are not based on this exemption and since any future P-T limit curves will also be based upon ASME Code Editions that have incorporated Code Case N-640, the exemption granting the use of ASME Code Case N-640 will not need to be extended into the period of extended operation.

Enclosure C

LSCS License Renewal Commitment List Updates

This Enclosure identifies commitments made in this document and is an update to the LSCS LRA Appendix A, Table A.5 License Renewal Commitment List. Any other actions discussed in the submittal represent intended or planned actions. They are described to the NRC for the NRC's information and are not regulatory commitments.

Changes to the LSCS LRA Appendix A, Table A.5 License Renewal Commitment List are as a result of the Exelon response to the following RAIs:

RAI B.2.1.13-2
RAI B.2.1.18-1
RAI B.2.1.18-2
RAI B.2.1.23-2

Notes:

- New or updated commitments are shown in the same order as the related RAI responses contained in Enclosure A.

- To facilitate understanding, relevant portions of the previously submitted License Renewal Commitment List have been repeated in this Enclosure, with revisions indicated. Previously submitted information is shown in normal font. Changes due to this submittal are highlighted with ***bolded italics*** for inserted text and ~~strikethroughs~~ for deleted text.

As a result of the response to RAI B.2.1.13-2 provided in Enclosure A of this letter, LRA Appendix A, Section A.5, Commitment 13, shown on page A-64 of the LRA is revised as shown below:

A.5 License Renewal Commitment List

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
13	Closed Treated Water Systems	Closed Treated Water Systems is an existing program that will be enhanced to: 1. Perform condition monitoring, including periodic visual inspections and non-destructive examinations, to verify the effectiveness of water chemistry control to mitigate aging effects. A representative sample of piping and components will be selected based on likelihood of corrosion, stress corrosion cracking, or fouling, and inspected at an interval not to exceed once in 10 years during the period of extended operation. The selection of components to be inspected will focus on locations which are most susceptible to age-related degradation, where practical. ***2. Monitor and trend drywell penetration cooling coil outlet temperatures monthly to ensure that adequate cooling is being provided to the concrete adjacent to the drywell penetrations.***	Program to be enhanced prior to the period of extended operation. Inspection schedule identified in commitment.	Section A.2.1.13 ***Exelon Letter RS-15-193 08/06/2015***

As a result of the responses to RAIs B.2.1.18-1 and B.2.1.18-2 provided in Enclosure A of this letter, LRA Appendix A, Section A.5, Commitment 18, shown on page A-68 of the LRA is revised as shown below:

A.5 License Renewal Commitment List

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
18	Aboveground Metallic Tanks	Aboveground Metallic Tanks is an existing program that will be enhanced to: 1. Perform a visual inspection of the tank shell, roof, and bottom interior surfaces for signs of loss of material on one of the cycled condensate storage tanks within five years prior to the period of extended operation. This inspection shall include both wetted and non-wetted surfaces and may be either direct visual inspection from inside the tanks or volumetric examination from outside the tank. A volumetric examination from outside the tank will include 25 percent of the tank surface area. Should the one-time inspection identify degradation, periodic inspections with an inspection frequency based on the rate of degradation will be established for both tanks. 2. Perform a visual inspection of the exterior surfaces of both cycled condensate storage tanks for loss of material each refueling interval. 3. Perform a volumetric examination of the tank bottom for both cycled condensate storage tanks for signs of loss of material whenever the tanks are drained. At a minimum, an inspection shall be performed within 10 years prior to the period of extended operation and subsequent inspections shall be performed in each 10-year period during the period of extended operation. ***The next inspection scope will include 100% of the accessible areas of each of the tank bottoms that are within 30 inches of the shell. Included in this scope are the patch plates that are directly exposed to the sand bed below. Additionally, 10 random locations of approximately one square foot each, outside of the 30 inch band, will be inspected. This inspection program will encompass approximately 20% of the tank bottom and will inspect all the susceptible areas which were found during the baseline inspections. Based on the results of this inspection, the scope will be reassessed for future tank bottom inspections, per the Corrective Action Program.*** 4. Perform an inspection of the caulking at the perimeter of the cycled condensate storage tank bases for signs of degradation each refueling interval ***(caulking inspections are supplemented with physical manipulation)***.	Program to be enhanced prior to the period of extended operation. Inspection schedule identified in commitment.	Section A.2.1.18 ***Exelon Letter RS-15-193 08/06/2015***

As a result of the response to RAI B.2.1.23-2 provided in Enclosure A of this letter, LRA Table A-5 on page A-70 of the LRA is revised as follows:

A.5 License Renewal Commitment List

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
23	***Unit 1*** One-time Inspection of ASME Code Class 1 Small-Bore Piping	***Unit 1*** One-time Inspection of ASME Code Class 1 Small-Bore Piping is a new condition monitoring program that will manage the aging effect of cracking in ASME Code Class 1 small-bore piping that is less than nominal pipe size (NPS) 4-inches, and greater than or equal to NPS 1-inch.	Program to be implemented prior to the period of extended operation. One-time Inspections will be performed within the six years prior to the period of extended operation.	Section A.2.1.23 ***Exelon Letter RS-15-193 08/06/2015***

As a result of the response to RAI B.2.1.23-2 provided in Enclosure A of this letter, LRA Table A-5 on page A-80 of the LRA is revised as follows:

A.5 License Renewal Commitment List

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
47	TLAA - Slip Joint Clamp	Prior to exceeding the limiting fluence value of 1.17E+20 n/cm^2 at the Unit 1 jet pump slip joint clamp location, estimated to be at 50.7 EFPY, revise the analysis for the slip joint clamps for a higher acceptable fluence value or take other corrective action such as repair or replacement of the clamps to ensure acceptable clamp preload.	Prior to the period of extended operation	Section A.4.2.10
48	***Unit 2 Inspection of ASME Code Class 1 Small-Bore Piping Program***	***Unit 2 Inspection of ASME Code Class 1 Small-Bore Piping Program is a new condition monitoring program that will manage the aging effect of cracking in ASME Code Class 1 small-bore piping that is less than nominal pipe size (NPS) 4-inches, and greater than or equal to NPS 1-inch.***	***Program to be implemented prior to the period of extended operation.*** ***The one-time inspections and the first set of periodic inspections will be performed within the six years prior to the period of extended operation.***	***Section A.2.2.2*** ***Exelon Letter RS-15-193 08/06/2015***