REQUEST FOR ADDITIONAL INFORMATION
BY THE OFFICE OF NUCLEAR REACTOR REGULATION
PERRY UNIT 1 LICENSE RENEWAL APPLICATION REVIEW (SAFETY)
ENERGY HARBOR NUCLEAR GENERATION LLC
PERRY, UNIT 1
DOCKET NO. 05000440
ISSUE DATE: 08/28/2024

NCSG RAI-10181-R1

Regulatory Basis

Pursuant to Title 10 of the *Code of Federal Regulations* (10 CFR) section 10 CFR 54.21(a)(3) requires an applicant to demonstrate that the effects of aging for structures and components will be adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis for the period of extended operation (PEO). One of the findings that the staff must make to issue a renewed license (10 CFR 54.29(a)) is that actions have been identified and have been or will be taken with respect to managing the effects of aging during the PEO on the functionality of structures and components that have been identified to require review under 10 CFR 54.21, such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the current licensing basis. In order to complete its review and enable making a finding under 10 CFR 54.29(a), the staff requires additional information in regard to the matters described below.

Background

Generic Aging Lessons Learned (GALL) Report AMP XI.M42 "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," as added by LR-ISG-2013-01, "Aging Management of Loss of Coating or Lining Integrity for Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," recommends managing the degradation of coatings/linings that can lead to loss of material of base materials and downstream effects such as reduction in flow, reduction in pressure or reduction in heat transfer when coatings/linings become debris. The program consists of periodic visual inspections of internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, treated borated water, waste water, fuel oil, and lubricating oil. Where the visual inspection of the coated/lined surfaces determines that the coating/lining is deficient or degraded, physical tests are performed, where physically possible, in conjunction with the visual inspection.

License renewal application (LRA) section B.2.27, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks Program," specifies periodic visual inspection of internal coatings/linings for in-scope components to manage the loss of coating integrity in heat exchangers, piping, piping components, piping elements, and tanks consistent with the GALL Report AMP XI.M42 in LR-ISG-2013-01. Section B.2.27 of LRA also specifies a baseline coating/lining inspection in the 10-year period prior to the PEO and states that the maximum interval of subsequent inspections will be consistent with Table 4a of the GALL Report AMP XI.M42 in LR-ISG-2013-01.

By letter dated June 27, 2024 (ML24180A010), LRA Supplement 2 revised Section B.2.27 to add exceptions to LRA Section B.2.27. The exceptions are applicable only to the Division 3 high pressure core spray (HPCS) fuel oil day tank (see issue below).

Issue

During the operating experience (OpE) audit, NRC staff reviewed recent inspection history on the following internally coated in-scope tanks:

- Division 1 and 2 emergency diesel generator (EDG) fuel oil storage tanks (PY-1R45A0002A(B))
- Division 1 and 2 EDG fuel oil day tanks (PY-1R45A0003(B))
- Division 3 EDG and/or HPCS fuel oil storage tank (PY-1R45A0004)
- Division 3 HPCS fuel oil day tank (PY-1R45A0005)

Also, during the OpE audit, the applicant stated that, except for the Division 3 HPCS fuel oil day tank, the above in-scope tanks would be visually inspected during the period of extended operation consistent with Table 4a of the GALL Report AMP XI.M42 in LR-ISG-2013-01 (confirmation of this statement is contingent on the applicant's response to RCI B.2.27, Question No. 1). However, LRA Supplement 2 states that the Division 3 HPCS fuel oil day tank (PY-1R45A0005), which was last visually inspected in 2010, would not be visually inspected during the PEO unless coating conditions are suspected to be degraded based on leading indicators in other EDG day tanks or the Division 3 HPCS fuel oil storage tank (identified as PY-1R45A0004 above). LRA Supplement 2 also states that debris found in the HPCS fuel oil pump suction strainers will also provide evidence if coatings are degrading.

Request

1. Explain how the Division 3 HPCS fuel oil storage tank and the Division 1 and 2 EDG fuel oil day tanks are considered to be leading indicators of coating/lining degradation of the Division 3 HPCS fuel oil day tank. The applicant's justification should include a discussion of the following as a minimum:
    - Similarity or differences between the tank base material types.
    - Similarity or differences between the internal coating types (use specific coating identifiers such as "Carboline 187").
    - Similarity or differences between the coating application dates and quality of the application, including similarities or differences in surface preparation between the tanks.

- Similarity or differences between tank internal environments (e.g. fluid type, stagnant or non-stagnant conditions, frequency of tank inventory turnover).
- Similarity or differences between tank geometries (if relevant to applicant's justification).

2. In order to support the claim that debris found in the HPCS fuel oil pump suction strainers will provide evidence of coating degradation, describe the following:
    - Mesh size of the strainers.
    - How frequently will these suction strainers be checked for debris?
    - How frequently will these suction strainers see flow due to demand for equipment testing and/or recirculation of the fuel oil in the tank?
    - How much coating debris can these suction strainers accommodate before flow is reduced below demand?
3. Discuss the risk of an undetected failure of the coating/lining of the Division 3 HPCS fuel oil day tank preventing the HPCS from performing its intended function. The applicant's discussion of the consequences of this undetected failure should address the following risks as a minimum:
    - Risk of fuel unavailability due to blocked suction strainers
    - Risk of adverse consequences downstream of the suction strainers due to small size coating debris bypassing the strainers
    - Risk of disabled or degraded HPCS system

NCSG RAI-10276-R1

XI.M36 External Surfaces - Stainless Steel Flex Hose Failures

Regulatory Basis

10 CFR 54.21(a)(3) requires an applicant to demonstrate that the effects of aging for structures and components will be adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis for the period of extended operation. For structures and components requiring review under 10 CFR 54.21, the staff must find (as required by 10 CFR 54.29(a)) that actions have been identified and have been or will be taken with respect to managing the effects of aging during the period of extended operation. To complete its review and enable the formulation of a finding under 10 CFR 54.29(a), the staff requests additional information regarding the matters described below.

RAI B.2.22-1: XI.M36 External Surfaces - Stainless Steel Flex Hose Failures

Background :

Perry license renewal report LRPY-OE-001, Revision 3, “Operating Experience Review” includes CR-2021-2192 and CR-2021-2296 that document leaking stainless steel flexible air supply hoses for safety relief valves 1B21F041B and 1B21F051B, respectively. The condition reports cite the suspected failure causes as “cyclic fatigue” or “cracking due to stress corrosion cracking.” Both CRs note that the causes of leaks are not yet known and that a failure analysis is needed to definitively determine the cause. The operating experience report tentatively assigns the condition reports to XI.M36 (External Surfaces Monitoring of Mechanical Components) with a citation to aging management review (AMR) item AP-209, which is associated with NUREG-1800, Revision 2, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," (SRP-LR) Further Evaluation Section 3.3.2.2.3, “Cracking Due to Stress Corrosion Cracking.”

Although failure analyses were ultimately not performed on the flex hoses for the leaks identified in 2021, the NRC identified more recent condition reports (CR-2023-02255 and CR-2023-02318) that document additional leaking stainless steel flexible air hoses for safety relief valves 1B21F041B and 1B21F047B, respectively. Perry’s operating experience review performed for these condition reports identified that previous leaks in the flexible air hoses for the same system had occurred in 2021 (SRV-0041B and -0051B), in 2017 (SRV-0041B), and in 2011 (SRV-0051B). An outside vendor performed a failure analysis for the leaking flex hoses from 2023, and their February 2024 (draft) and April 2024 (final) failure analysis reports determined the cause to be outside diameter chloride induced stress corrosion cracking.

As recommended in the vendor’s failure analysis report, Perry initiated CR-2024-01530 on February 27, 2024, to identify the source of the chlorides found on the flexible hoses. However, the investigation did not find the source of the chloride contamination. The aging management evaluation performed as part of the condition report and completed on April 24, 2024, stated, “This does not appear to be an aging management issue. The failure in the report is some type of stress-based cracking, potentially from chlorides.” Additionally, the condition report states, “Available replacement hoses contain no detectable contaminants.”

Perry’s operating experience report, LRPY-OE-001, also states that, consistent with Regulatory Issue Summary 2014-06, Revision 1, “Consideration of Current Operating Issues and Licensing Actions in License Renewal” (ML23167A044), Perry will monitor significant operating experience that could challenge the adequacy of the aging management programs after the license renewal application submittal and supplement the application as appropriate. The regulatory issue summary specifically discusses the need for the NRC staff to receive information about late-breaking operating experience if it materially affects the license renewal application (LRA). The staff notes that Perry’s first annual update, issued on July 3, 2024, did not include the late-breaking operating experience information from the recently completed failure analysis report.

Perry’s LRA Supplement 2 (dated June 27, 2024 (ML24180A010)) modified LRA Sections 3.2.2.2.6, 3.3.2.2.3, and 3.4.2.2.2, “Cracking Due to Stress Corrosion Cracking,” and LRA Sections 3.2.2.2.3, 3.3.2.2.5, 3.4.2.2.3, “Loss of Material due to Pitting and Crevice

Corrosion,”.to include statements “This section follows up supporting this assertion [concerning no environmental halides] by not identifying operating experience typically related to having salt deposits or other industrial contamination.”

Issue :

The NRC staff identified the following issues with the above information.

1. Perry’s aging management evaluation, conducted for CR-2024-01530, concluded that the failure analysis report’s determination (i.e., chloride induced stress corrosion cracking of the stainless-steel flexible air supply hoses) was not an aging management issue. The staff notes that chloride induced stress corrosion cracking, as discussed in SRP-LR Sections 3.2.2.2.6, 3.3.2.2.3, and 3.4.2.2.2, is an aging effect requiring management for stainless steel components exposed to air environments containing halides. Although the above SRP-LR sections pertain to chloride sources from outdoor air, based on Perry’s plant-specific operating experience, some stainless-steel components in an indoor uncontrolled air environment are being exposed to an unidentified source of chlorides, causing stress corrosion cracking. For the associated stainless steel flexible hose AMR items, LRA Table 3.1.2-2 notes that there are no aging effects requiring management and there is no associated aging management program. This is inconsistent with the failure analysis conclusions.
2. Because Perry was unable to identify the source of the chlorides causing the stress corrosion cracking, comparable components (i.e., stainless steel flexible hoses exposed to indoor uncontrolled air) may also be susceptible to the same plant-specific operating experience aging effect (i.e., chloride induced stress corrosion cracking).
3. The NRC staff specifically discussed the associated issues during the XI.M36 audit breakout session in January and expressed an interest in the results of the failure analysis. The failure analysis vendor provided draft and final versions of its report in February and April 2024, respectively. Perry initiated follow-up condition report CR-2024-01530 on February 27, 2024, and completed its aging management review on April 24, 2024. However, Perry did not provide the late-breaking operating experience information in its annual update issued on July 3, 2024. Although Perry said that it will monitor significant operating experience that could challenge the adequacy of the aging management programs, the process for controlling this review and for determining the effects on the LRA is unclear. .
4. It’s not clear how Perry determined that all flex hoses in the warehouse did not contain any chlorides. The outer surface of the stainless-steel pressure retaining portion of the flexible hose is covered by an integral metal mesh. The results of the testing may not be valid unless the test looking for chlorides was conducted on the pressure retaining surface of the flex hose.
5. Based on the plant-specific operating experience for failures of stainless steel flex hoses, it can be reasonably concluded that chloride induced stress corrosion cracking has occurred on multiple occasions at Perry. However, because the source of the chloride contamination could not be identified, it is unclear whether the supplemented statements for LRA Sections

3.2.2.2.3, 3.2.2.2.6, 3.3.2.2.3, 3.3.2.2.5, 3.4.2.2.2, and 3.4.2.2.3 regarding "not identifying operating experience" related to chloride contamination is correct.

Request :

1. Because chloride induced stress corrosion cracking was concluded to be the cause of the degradation of the stainless-steel flexible air supply hoses to the safety relief valves, either update LRA Table 3.1.2-2 to identify this aging effect requiring management or provide a basis for why this age-related degradation does not need to be managed. If applicable, include the aging management program to be used for managing this aging effect and provide information for how degradation prior to a loss of intended function of an air system will be detected with the program. Specifically discuss how the outside diameter initiated cracking will be detected, given that the pressure retaining surface is covered by an integral metal mesh.
2. Because the source of the chlorides causing the stress corrosion cracking was not able to be identified, either update other LRA Tables for comparable components (i.e., stainless steel flexible hose exposed to indoor uncontrolled air) or provide a basis for why this aging effect requiring management does not apply to the other comparable components.
3. Because Perry did not provide the recently developed information relating to the failure analysis results (i.e., the leaks on the stainless-steel flexible hoses were caused by chloride induced stress corrosion cracking), provide information about the process for performing the reviews described in LRPY-OE-001 of post submittal operating experience and for determining any effects on the LRA.
4. Because the outer surface of the stainless-steel pressure retaining portion of the flexible hose is covered by an integral metal mesh, provide information about how the testing was performed to determine that all other stainless steel flexible hoses in the warehouse do not contain chloride contaminants and the associated aging effect requiring management would not apply to the replacement components.
5. Because recent operating experience has identified chloride induced stress corrosion cracking, either provide the basis for the accuracy of the statements in the supplemented statements for LRA Sections 3.2.2.2.3, 3.2.2.2.6, 3.3.2.2.3, 3.3.2.2.5, 3.4.2.2.2, and 3.4.2.2.3 regarding not identifying operating experience related to chloride contamination that could cause stress corrosion cracking or loss of material (due to pitting or crevice corrosion) of stainless steel, or update these LRA sections as necessary.

NVIP RAI-10231-R1

Question 1

Regulatory Basis

10 CFR Part 54.3 defines a time limited aging analyses as those licensee calculations and analyses that:

(1) Involve systems, structures, and components within the scope of license renewal, as delineated in § 54.4(a);

(2) Consider the effects of aging;

(3) Involve time-limited assumptions defined by the current operating term, for example, 40 years;

(4) Were determined to be relevant by the licensee in making a safety determination;

(5) Involve conclusions or provide the basis for conclusions related to the capability of the system, structure, and component to perform its intended functions, as delineated in § 54.4(b); and

(6) Are contained or incorporated by reference in the CLB.

10 CFR 54.21(c)(1) states a list of time-limited aging analyses, as defined in § 54.3, must be provided. The applicant shall demonstrate that:

(i) The analyses remain valid for the period of extended operation;

(ii) The analyses have been projected to the end of the period of extended operation; or

(iii) The effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

Request for Additional Information 4.2-1

<u>Background</u>

LRA Table 4.2-2, "PNPP RPV Beltline USE Data for 54 EFPY" and LRA Table 4.2-3, "PNPP Beltline RPV Material ART Data for 54 EFPY" provide material property information for reactor pressure vessel materials.

<u>Issue</u>

During its audit, the staff reviewed the certified material test reports associated with the applicant's reactor pressure vessel materials to determine whether the material information (e.g., initial RT_{NDT}, %Cu, %Ni, initial USE, margin values) for the RPV materials contained in LRA Tables 4.2-2 and 4.2-3, were consistent with the applicant's current licensing basis or based on information from certified material test reports or fabrication records for the specific material or weld type.

During its review, the staff noted that the %Cu and %Ni content values for Lower Shell Plate (i.e., Heat Nos C2448-1, C2448-2 and A1068-1) in LRA Tables 4.2-2 and 4.2-3 were inconsistent with the "check" values (i.e., measurements taken from the product form) documented in the CMTRs.

<u>Request</u>

For the Lower Shell Plate (i.e., Heat Nos C2448-1, C2448-2 and A1068-1), justify that the %Cu and %Ni content values for these RPV materials in LRA Tables 4.2-2 and 4.2-3 are inconsistent with the “check” values (i.e., measurements taken from the product form) documented in the certified material test reports.

Question 2

Regulatory Basis

10 CFR 54.21(a)(3) requires an applicant to demonstrate that the effects of aging for structures and components will be adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis for the period of extended operation. 10 CFR 54.21(d) requires the FSAR supplement for the facility to contain a summary description of the programs and activities for managing the effects of aging for the period of extended operation determined by 10 CFR 54.21(a). One of the findings that the staff must make to issue a renewed license (10 CFR 54.29(a)) is that actions have been identified and have been or will be taken with respect to managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require review under 10 CFR 54.21, such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the current licensing basis. In order to complete its review and enable making a finding under 10 CFR 54.29(a), the staff requires additional information in regard to the matters described below.

Background

The Program Description for the BWR Vessel ID Attachment Welds AMP (XI.M4) in Revision 2 of NUREG-1801, “Generic Aging Lessons Learned (GALL) Report” (ML103490041) states that the program includes inspection and flaw evaluation in accordance with the guidelines of a staff-approved Boiling Water Reactor Vessel and Internals Project report (BWRVIP-48-A) to provide reasonable assurance of the long-term integrity and safe operation of boiling water reactor (BWR) vessel inside diameter (ID) attachment welds.

In Appendix A of the PNPP LRA, the Updated Final Safety Analysis Report Supplement, paragraph A.1.13 states, “The BWR Vessel ID Attachment Welds aging management program is an existing condition monitoring program that includes the inspection and evaluation recommendations within BWRVIP-48 and the requirements of ASME Code, Section XI.”

Appendix C of the LRA, BWRVIP Applicant Action Items, lists among BWRVIP documents credited for PNPP license renewal, BWRVIP-48, Revision 1, “Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines.”

In LRA Supplement 2, Attachment No. 51, Section B.2.13 states, “…prior to entering the subsequent 10-year ISI intervals, PNPP would have to either comply with the ASME Code requirements and NRC approved BWRVIP-48 guidance, or request [NRC approval of an alternative to] the requirements consistent with what PNPP has done during the initial operating period.”

Issue

There is a discrepancy among the descriptions of requirements and guidance that will be used to provide reasonable assurance of the long-term integrity of the ID attachment welds. In addition to meeting the requirements of ASME Code Section XI, the inspection and flaw evaluation guidelines approved by the staff are in BWRVIP-48-A. The LRA, as supplemented, does not make clear whether the applicant intends to use BWRVIP-48-A.

Request

Confirm that the UFSAR will credit the staff-approved guidance in addition to the ASME Code requirements, or that staff approval for an alternative to the approved guidance will be sought prior to the start of subsequent 10-year ISI intervals.