CGN Questions on License Renewal in the U.S.

Nuclear

March 2025

1. SSCs Intended Functions of SSCs Within the Scope of License Renewal

- Question 1.(1) What are the primary objectives and purposes of delineating the intended functions of systems, equipment, and components? Based on U.S. practices, are there differences in the intended functions addressed by maintenance rules (e.g., for license renewal) versus those focused on during the operational license period?

- Response 1.(1). The primary objective and purpose of delineating the intended functions is to ensure the safety functions needed to respond to a design basis event are protected and managed such that the safety function is accomplished when needed. 10 CFR Part 54 specifies the intended functions that are to be protected and management in Part 54.4. When an application for license renewal is submitted to NRC, the licensee must identify the systems, structures, and components that are relied upon to fulfill the 54.4 functions. The NRC then reviews the information to ensure the scope of the license renewal review is complete and accurate regarding systems, equipment, and components relied upon to perform the 54.4 functions. More details are available in NEI 95-10 and NEI 17-01 (section 3.1 in both documents) which are endorsed by the NRC in Regulatory Guide 1.188.

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- Question 1.(2) Could you provide examples of methodologies used in U.S. nuclear power plants to identify the intended functions of systems, equipment, and components?

- Response 1.(2) See NEI 95-10 (for first license renewal) and NEI 17-01 (for subsequent license renewal) Sections:

  3.1, Systems, Structures, and Components Within the Scope of License Renewal,

  3.2, Intended Functions of SSCs Within the Scope of License Renewal, and

  3.3, Documenting the Scoping Process

  This methodology has been used by U.S. utilities that have submitted (LR) and subsequent license renewal (SLR) applications, since it is endorsed by the NRC.

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- Question 1.(3) Is there a relationship between the intended functions of components and those of systems/equipment? Is the definition of the intended functions of a component varies among different power plants due to differences in their designs and are there other factors involved?

- Response 1.(3) There is a relationship between the intended function of components (passive) and those of systems/equipment (active) as defined in the regulatory process for LR and SLR. The systems/equipment (active) functions are primarily those listed in 54.4, which includes reactor core cooling, maintaining the reactor coolant pressure boundary, and maintaining the containment building integrity. The intended functions of components (passive) within the 54.4 systems/equipment include pressure boundary, electrical continuity, filter, heat transfer, etc. (see NEI 95-10 and NEI 17-01, Table 4.1-1). The definitions of intended function of components does vary by design, but a typical or standard approach is described in NEI 95-10 and NEI 17-01, Section 4, Integrated Plant Assessment.

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- Question 1.(4) In U.S. nuclear plant License Renewal Applications (LRAs), components with different intended functions (e.g., piping and piping components in Table 2.3.1-1 from example LRA) are grouped under the same category. Why are components with distinct functions classified together, and what criteria are used for such grouping?

- Response 1.(4) The groupings in the table are based on components with the same "passive" intended function (e.g., pressure boundary, heat transfer, etc.). These components may be part of systems/equipment with different "active" intended functions (e.g., core cooling, containment integrity, etc.), but they have the same "passive" function that must be maintained by an aging management program. For license renewal, aging management programs must be put in place to ensure the "passive" function is maintained, which helps ensure that the "active" function is not challenged.

  NOTE: "Active" functions are monitored and managed primarily through operating information (e.g., flow, pressure, temperature, etc.) and periodic surveillance. Since "passive" functions may or may not be managed by these existing processes or programs, the license renewal regulatory process placed emphasis on aging management of "passive" components.

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- Question 1.(5) In the LRAs of U.S. nuclear power plants, aging effects for components are identified based on their specific intended functions. Why is it necessary to distinguish between different intended functions when the same component material and environment generally lead to similar aging effects? Should the impacts of different intended functions be considered when identifying aging effects?

- Response 1.(5) The aging effects for components are primarily identified by the material and environment combinations (e.g., stainless steel in borated water), not the intended functions (e.g., pressure boundary, heat transfer). However, since a component like a heat exchanger may have both a "pressure boundary" AND a "heat transfer" passive function, the resulting aging management program(s) may be different. Therefore, the impacts of different intended functions are considered when identifying aging management programs.

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- Question 1.(6) Do U.S. plants identify all intended functions of a component? Current LRAs provide summary tables—are all functions listed for individual component? For example, if non-safety-related components interfacing with safety-related components are included, is spatial impact analysis still conducted?

- Response 1.(6) Yes, the requirement is that all intended "passive" functions are identified to ensure that the appropriate aging management programs are implemented to ensure the function is maintained. Likewise, all 54.4 functions are identified to ensure systems/equipment/components are included in scope for an aging management review.

1. SSCs Intended Functions of SSCs Within the Scope of License Renewal

- Question 1.(7) How is component-level screening implemented? While EPRI guidelines specify component scopes for different equipment types, U.S. LRAs often exclude piping, valves, and pumps from detailed component-level analysis. What justifies this approach, and how do plants achieve component-level screening and aging effect identification?

- Response 1.(7) If the component is part of an in-scope system per 54.4, then it is subject to an aging management review. The screening process then identifies which components are passive and long-lived (see NEI 95-10 and NEI 17-01 for more details on this process). All passive and long-lived components are subject to an aging management review to identify the applicable aging effects and the appropriate aging management program(s) needed to manage the aging effects, as described in the NEI guidance documents (95-10 and 17-01).

2. Beyond Design Basis Accident related SSCs

- Question 2.(1) In U.S. nuclear plant LRA reports, the scope of systems considered for beyond-design-basis accidents varies significantly across plants. Does the regulatory agency have unified evaluation criteria or principles? (e.g., ATWS information for Turkey Point Nuclear Units 3 and 4 SLRA focus on mechanical systems vs. Waterford 3 LRA with no focus on mechanical systems)

- Response 2.(1) Yes, the regulatory process requires that the current licensing basis (CLB) be used to define what is in-scope per 54.4. The regulated events listed in 54.4(a)(3) includes fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), and station blackout (10 CFR 50.63). Since each operating nuclear power plant had flexibility in demonstrating compliance with these regulations, the resulting CLB may be different from plant-to-plant. Therefore, the scope of systems considered may vary, but must be the NRC-approved systems associated with the individual plant’s CLB.

3. Equivalent Anchor

- Question 3.(1) What scenarios are covered by "equivalent anchor" in U.S. plant design documents? Please provide examples.

- Response 3.(1) The "equivalent anchor" definition is used whenever a system or structure is required to be seismically qualified, but the seismic analysis information is not available or does not clearly indicate the end points for the seismic analysis. In those cases, the "equivalent anchor" concept may be used. For example: (1) seismic piping segment that ends at a base-mounted component (e.g., pump, tank, etc.), and (2) a point where buried piping exits the ground (e.g., where the ground acts like an anchor). Appendix F, Section 4, of NEI 95-10 and NEI 17.01 provides more details on "equivalent anchor" examples and guidelines.

3. Equivalent Anchor

- Question 3.(2) Regarding NEI 95-10's principles for identifying equivalent anchor, how do plants evaluate non-safety components that indirectly impact safety? What factors and differences should be emphasized when applying these principles? (see 95-10 sections 4.2 and 4.3)

- Response 3.(2) The examples listed from Appendix F, Section 4.2 and 4.3, are good examples of the different options. In Section 4.2, it is indicated that a licensee may have an existing definition of an "equivalent anchor" in the seismic analysis that is part of the plant's CLB. If so, that definition will be used for the review of the boundaries for seismic analysis relevant to license renewal. In Section 4.3, it is indicated that it can be assumed the seismic analysis end point, or "equivalent anchor", for a piping segment can be a large component (e.g., heat exchanger) that restrains the seismic forces and moments in three orthogonal directions (x, y, and z). For seismically qualified piping segments and components that are connected to non-safety and non-seismic piping segments, the boundary for the aging management review extends to the next "equivalent anchor" of the attached non-safety piping segment.

4. PWR Aging Management Program: PWR internals (AMP M16A)

- Question 4.(1) Do U.S. nuclear power plants have a comprehensive aging monitoring and evaluation system specifically for reactor internals (not limited to loose components or vibration monitoring)? Or are there research institutions conducting modeling studies that simulate the same/similar operating conditions?

- Response 4.(1) For PWRs, EPRI guidance in MRP-227 Revision 1-A provides the NRC-approved aging management guidance for long-term operation (LTO) and license renewal beyond 40-calendar years. This is available from EPRI website: https://www.epri.com/research/products/000000003002017168

4. PWR Aging Management Program: PWR internals (AMP M16A)

- Question 4.(2) Have there been cases of cracking or abnormal defect indications in reactor internal components in U.S. nuclear power plants? Regardless of whether such cases exist, how should the evaluation of crack propagation or defects (hypothetical) in reactor internals be considered?

- Response 4.(2) EPRI guidance mandates the use of “NRC-approved” engineering evaluation methodologies for evaluation of crack propagation or defects (actual or hypothetical) in PWR reactor internals. One example of these methodologies is ASME Boiler and Pressure Vessel Code Section XI evaluations, if they are applicable to the given situation. Another example is the PWR Owners Group’s (PWROG) evaluation methods that were approved by US NRC, as documented in WCAP-17096-NP-A, Revision 3, which is available at NRC website: https://www.nrc.gov/docs/ML2324/ML23248A258.pdf

5. Aging Management Program: Flow Accelerated Corrosion (AMP M17)

- Question 5.(1) The AMP contents: “Scope of programme: Since there are no materials that are known to be totally resistant to wall thinning due to erosion mechanisms, susceptible components of any material may be included in the erosion portion of the program” - How to determine the systems and equipment of erosion concern in LR of U.S. nuclear power plants?

- Response 5.(1) For license renewal in general, Piping & Instrument Drawings (P&ID's) are used to review and identify the boundaries of systems, structures, and components that are within the scope of the license renewal rule (10 CFR 54.4). These P&ID's are often marked up and color coded to create LR project specific boundary drawings that depict the scoping boundaries. These SSCs that are within the scope of LR represent a subset of the population that may already be included as part of the existing station flow accelerated corrosion (FAC) or erosion program.

  For a comprehensive erosion program, guidance for identifying systems susceptible is provided in Section 6.2 of EPRI report 3002023786, which has superseded 3002005530 referenced in the GALL (NUREG-1801). Additional details are provided in Appendix E.

  The results are documented in an Erosion Susceptibility Evaluation which typically includes a line level evaluation, review of station documents (e.g., from the corrective action program), and CHECWORKS results. The line level evaluation is documented in tables and color-coded P&ID's. The tables list all the lines potentially susceptible to erosion, as well as columns that document susceptibility or exclusion criteria for each erosion mechanism (i.e., cavitation, LDI, solid particle, and flashing). Lines with large pressure drops are prioritized. Inspection locations are chosen for multiple reasons including industry experience, CHECWORKS modeling, plant experience (e.g., leaking valves or previous erosion issues), and engineering judgement.

5. Aging Management Program: Flow Accelerated Corrosion (AMP M17)

- Question 5.(2) Are there specific examples of screening, acceptance criteria, and corrective actions for erosion inspection areas of concern?

- Response 5.(2) For screening, the best reference is EPRI report 1022187 "Plant Susceptibility Screening for Erosive Attack". Specific examples for cavitation screening are in Appendix B.

  Regarding acceptance criteria, guidance for evaluating worn components is in Section 6.8 of 3002023786. Minimum acceptable wall thickness is typically calculated according to the construction code of record for the plant (e.g., ASME Boiler & Pressure Vessel Code), ASME Code Case N-597, ASME B31.1, etc.

  Corrective actions include repairs, replacements, and design changes. Countermeasures are listed in Appendix G of 3002023786. Many of these aspects are covered in a new Computer Based Training Module on Erosion and Piping Systems. To view this CBT on EPRI.com, search for product 3002029269, then click on "Events & Training" near the top of the window.

6. Aging Management Program: Open Circulating Water Systems

- Question 6. The content of the inspection program in GALL 1801 M20 includes supervision and control of biological accumulation. Can you illustrate with actual examples how the power plant supervises and controls biological accumulation? How the inspection methods and acceptance criteria are established?

- Response 6. AMP XI.M20 is based on Generic Letter 89-13 (GL 89-13) and resolution of Generic Safety Issue 51 (GSI-51). Operating experience is included in GL 89-13 regarding flow blockage and other operating impacts due to such issues as macroscopic biological fouling from biota, such as blue mussels, oysters, or clams. Some of the controls include water chemistry and chemical additives (e.g., chlorination or other biocides); periodic flushing of piping and components to remove fouling materials, corrosion products, debris, silt; and testing for heat transfer capability.

  For systems and components subject to loss of material, periodic wall thickness measurements (NDE) are taken and trended to determine when corrective actions are needed to maintain the safety function of the system. Acceptance criteria would be based on the design of the component regarding minimum wall thickness.

  Additional information regarding water chemistry guidelines can be found in EPRI Report 3002019654, Open Cooling Water Chemistry Guideline. The purpose of this Guideline is to assist power plant chemists and engineers with selecting, evaluating, and applying a total water treatment program to open cooling water systems to mitigate or prevent microbiological growth, corrosion, scaling, macrobiological fouling, and siltation.

7. Aging Management Program: Closed Treated Water Systems, Compressed Air Surveillance, Internal Surface Inspection of Misc. Piping & Duct Components

- Question 7.(1) AMPs allow opportunistic inspections - As for the opportunistic inspection in the AMP program, how do the U.S. nuclear power plants implement the opportunistic inspection, are there any specific examples?

- Response 7.(1) Opportunistic inspections are performed when systems are opened and internal surfaces are exposed during the course of preventive maintenance or corrective action maintenance work. Opportunistic inspections are often performed by maintenance personnel. US utilities have 1) sometimes established training requirements for plant personnel, including maintenance, that include instruction on recognizing the different types of aging effects and mechanisms, 2) sometimes specified that systems or programs engineering personnel be contacted to perform the opportunistic inspection (e.g., for the M41 Buried Pipe program). Some utilities have reported 1) revising procedures associated with work planning that specify direction to include steps in work orders to perform and document visual inspections any time equipment is opened for maintenance work, or 2) tagging specific components within the scope of license renewal and aging management, such that anytime these components are subject to maintenance work, there are directions and requirements to perform and document inspections. There are variations in the manner in which this is done within procedures and work planning processes, based on the utility specific practices and organization.

7. Aging Management Program: Closed Treated Water Systems, Compressed Air Surveillance, Internal Surface Inspection of Misc. Piping & Duct Components

- Question 7.(2) For cases where internal surface inspection results do not meet standards, whether additional expanded inspections are needed, and how to determine the quantity and proportion of these additional inspections？

- Response 7.(2) When visual inspections identify adverse findings, these findings should be entered into the corrective action program for disposition. Follow-up actions should include evaluating the severity, cause, extent of condition, and proposing any follow-up actions. Some aging management programs have specific guidance on recommended extent of condition inspection quantities. When not specified by the individual aging management program recommendations (GALL / GALL-SLR / IGALL), these are utility and situational specific circumstances and rely on following the existing corrective action process. The quantity of recommended follow-up inspections will be specific to the cause, extent of condition, and severity of damage, among other factors. As such, a singular and universal value or guidance likely lacks technical basis otherwise.

  One potential baseline example is ASME Section XI Code Case N-513 for evaluation and temporary acceptance of local flaws in moderate energy class 2 and 3 piping; whereby, an expanded sample set of 5 additional inspections are recommended. However, that code case should be reviewed in detail to understand the situations, conditions, and constrains under which it applies (i.e., safety class of systems, types of degradation, known operating experience with similar types of degradation, etc.) before using it as a basis for any other situations.

8. AMP: One-time Inspection, Selective Leaching (M32, M33)

- Question 8.(1) What is the basis for selecting typical samples for one-time inspection in LR of U.S. nuclear power plants?

- Response 8.(1) For one-time inspections under the M32 AMP, inspections are chosen considering technical considerations such as susceptibility to degradation. As an example, M32 often performs verifications on the effectiveness of chemistry programs (water chemistry, fuel oil, and lube oil). Inspection locations may be focused on low flow and stagnant areas of the systems where chemistry treatments may be less effective. For oil-based systems, this might entail locations at the bottom of the stagnant systems, where water is more likely to accumulate. However, the M32 program covers more than just chemistry verification one-time inspections. Location selection for other material-environment locations may be based on considerations of similar susceptibility or severity of the environment and past operating experience. Non-technical considerations are also often taken into account, such as taking credit for existing activities that may satisfy the inspection requirement while being sufficiently representative of the rest of the population, as well as considering accessibility of the component, and applicability of different NDE techniques (e.g., components of sufficient size and geometry to implement effective NDE methods, such as ultrasonics).

  For the M33 selective leaching program, similar considerations are taken into account. Specifically, susceptibility, previous operating experience, severity of the environment relative to the aging effect (e.g., water chemistry, temperature, halides, fluid flow conditions), accessibility of components, opportunities for inspection (existing planned or even unplanned opportunities), and applicability of potential NDE methods.

8. AMP: One-time Inspection, Selective Leaching (M32, M33)

- Question 8.(2) What are the methods used to implement selective leaching one-time inspections in LR of U.S. nuclear power plants, whether destructive inspections are included? Can you show us some examples?

- Response 8.(2) US utilities used to perform selective leaching inspections using visual examination and hardness testing. However, portable field hardness testing returned variable results. The industry, and NRC guidance in GALL R2 and GALL-SLR, moved toward reliance on "mechanical" examinations (scratching, scraping, abrading surfaces in order to remove any potentially dealloyed material). Many utilities have relied upon destructive examinations, as it is more confirmative. Where possible, destructive exams are performed on components that are removed from service for other reasons (e.g., valve bodies removed due to isolation or active function issues). Currently, most utilities rely on a combination of visual + mechanical inspections, and/or destructive examinations; this is consistent with the latest version of NUREG-2191 (GALL-SLR).

  EPRI has recently performed research demonstrating the ability to use ultrasonic techniques on certain gray cast iron situations, as well as electromagnetic NDE methods for gray cast iron piping (3002020830, 3002020832, 3002023785). Additional information on selective leaching aging management programs can be found in 3002016057 and 3002026340. One US Utility has had success with using time-of-flight diffraction ultrasonic testing to detect and quantify dealloying in aluminum bronze components (US NRC documents ML13316B905, ML17107A319, ML17146B242, ML17146B224 available on the US NRC's website via ADAMS search: https://adams-search.nrc.gov/home).

8. AMP: One-time Inspection, Selective Leaching (M32, M33)

- Question 8.(3) Does the one-time inspection have quantitative inspection parameters, specific acceptance criteria and corresponding corrective actions?

- Response 8.(3) In accordance with NUREG-1801 (Revision 2) and NUREG-2191, inspections findings should be compared to any applicable ASME requirements (e.g., wall thickness) or similar design basis information (such as pressure and structural integrity). Overall, any adverse and/or unexpected inspections findings should generally be entered into the corrective action program for evaluation as a matter of good practice. Although some adverse findings may not necessarily violate design basis requirements (pressure/structural integrity), the owner of the AMP should consider whether the as-found conditions are unexpected and possibly warrant further inspections to understand the extent of condition and severity of the issue; there is no universal criteria for this. Adverse findings should also be evaluated on the basis of determining whether the component would have continued to be able to perform it's intended function throughout the remaining life the plant, based on the severity and extent of degradation found at the time of the inspection. This is in accordance with the scope of the program (M32 of GALL, GALL-SLR, as well as IGALL AMP 119) which states the program verifies the absence of an aging effect, or, if present, that it is occurring so slowly as not to affect the intended function of the component throughout the extended life of the plant.

9. AMP for Bolts (AMP M3, M18, S3, S6)

- Question 9.(1) The AMP requires volumetric inspection of fasteners with specifications greater than 1 inch (structural bolts) and 2 inches (pressure bolts) and measured yield strength greater than 150ksi (1034MPa) - What is the basis for the specified yield strength value of 150 ksi (1034 MPa)?

- Response 9.(1) The NRC identified bolting integrity issues as a generic safety issue as documented in GSI 29, "Bolting Degradation or Failure in Nuclear Power Plants." In response, EPRI conducted research on the generic issue and documented the results and guidance in EPRI NP-5769 (April 1988), "Degradation and Failure of Bolting in Nuclear Power Plants," which was submitted to the NRC. NRC endorsed the EPRI guidance as documented in NUREG-1339 (June 1990), "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants." The conclusion was that "the criterion of actual yield strength, greater than or equal to 150 ksi should be used as the level for consideration of SCC vulnerability." Background details are included in the referenced documents.

9. AMP for Bolts (AMP M3, M18, S3, S6)

- Question 9.(2) In The AMP, pressure bolts are inspected in accordance with ASME Volume XI, Table B-G-1 of the IWB, and IWB is only applicable to Class 1 components. Do Class 2 and 3 pressure-bearing fasteners not require volumetric inspection?

- Response 9.(2) Bolting inspections can fall under various AMPs which have different inspection guidelines. For Class 1 components included in XI.M3, the requirement is for volumetric inspection in accordance with IWB. For Class 2 components included in XI.M18, the requirement is for volumetric inspection in accordance with IWC. For other pressure-bearing fasteners, including Class 3, the requirements are primarily visual inspection (e.g., XI.S3 specifies IWF and VT-3, XI.S6 specifies "primarily visual inspections by personnel qualified to monitor structures and components"). Therefore, some Class 2 components do require volumetric inspection per IWC.

  Also, for AMP XI.S3, certain high strength closure bolting (i.e., greater than or equal to 150 ksi and greater than 2 inches in diameter) that may be subject to SCC, volumetric examination is required regardless of code classification.

10. AMP: Above-ground Metal Storage Tanks (M29)

- Question 10. AMP M29 states: “Detection of Aging Effects: If the exterior surface is not coated, visual inspections of the tank’s surface are conducted within sufficient proximity (e.g., distance, angle of observation) to detect loss of material.” - How to implement this requirement in the aging management of metal storage tanks in U.S. nuclear power plants? Are there any examples?

- Response 10. AMP M29 does not provide specific requirements on what constitutes "sufficient proximity". Generally, it is expected to follow existing site procedures and processes for similar inspections, and well as standard good engineering practices and judgement. Site procedure and processes may vary based on the safety class designation of the tank. Inspections might include use of scaffolding for areas inaccessible or not visible from grade level, use of binoculars, or even use of drones if necessary / desired to ensure the inspection requirements are satisfied.

11. AMP: Structural Monitoring (S6)

- Question 11. In the "GALL S6 Structural Monitoring Aging Management Program", how are structural supports inspected within designated areas? Is it possible to conduct sampling inspections? If so, what are the principles for sampling, inspection frequencies, and general acceptance criteria? Can sampling inspections also be conducted on other components, such as concrete and steel parts?

- Response 11. Based on a recent survey of U.S. utilities performing Structural Monitoring Program (SMP) walkdowns, the survey respondents indicated they do a 100% inspection primarily via systems and structures walkdowns per GALL AMP XI.S6 (or related AMP) every 5 years. However, EPRI Report 3002018488, "Structures Monitoring Program Guidelines: Best Practices and Example Procedure" contains the following guidance regarding the scope of inspection (page 7 of 52):

  "All structural elements require a general inspection to check for gross deficiencies. For detailed examination, a sampling approach for some structural elements in a given area that are representative of the conditions for the area may be appropriate (e.g., if the element or set of elements is very large and has a largely consistent condition). These same elements should be examined in detail in subsequent inspections. Note that if degraded conditions are found, the number of monitored elements should be increased commensurately with the degradation mechanism. The following elements may be examined in detail on a sampled basis (suggested sampling is provided, but the number of sampled locations should be determined by the judgment of the Responsible Engineer): Concrete and steel beams: 1–2 per area; Above-grade concrete walls: 1 per area; Concrete slab: 1 per area; Interior concrete columns and steel columns: 1 per area; Platforms, handrails, and ladders: 1–2 per area (if applicable); Component supports: 5–50 total, dependent on type of component".

  NOTE: More detail is included in the EPRI report.

12. TLAA Analysis Term Determination

- Question 12. When determining the list of TLAA analysis items, is it necessary to screen each AMR Commodity Group and its corresponding components that are determined as "requiring further TLAA evaluation" according to the six screening criteria of TLAA?
- Response 12. Yes, in addition to the generic list of TLAAs identified in NEI 95-10, NEI 17-01, NUREG-1800, and NUREG-2192; there are plant-specific TLAAs that require further review to determine the full scope of TLAAs. Examples of the potential plant-specific TLAAs are provided in NUREG-0800 and in NUREG-2192 (e.g., see Table 4.7-1, NUREG-2192).

13. Fatigue Analysis of Metal Components

- Question 13. Are there any U.S. power plants that have a situation where the cumulative usage factor (CUF) for fatigue is greater than 1 during the design phase? If so, how is it handled during the license renewal evaluation?
- Response 13. Yes, when plants are seeking license renewal for continued operation, CUF values greater than 1 can be addressed for operating U.S. power plants through fatigue monitoring and/or in-service inspection programs. The need to consider environmentally assisted fatigue (EAF) in fatigue assessments has necessitated such an option for new designs. While there hasn't been a specific instance in the U.S., the ASME Boiler and Pressure Vessel Code committees have anticipated this situation and developed a nuclear code case for such an instance. Code Case N-919 provides an alternative to the standard ASME Section III fatigue design requirements where the CUF, including the impact of the environment, CUFen, shall not exceed 1.0 for the first 10 years of plant operation. Additionally, the utility is required to establish an operating plant fatigue assessment that addresses the remaining portion of the service cycles in the design specification. The operating plant tools for existing plants (fatigue monitoring, flaw tolerance assessments) are available for assessing the remaining service. One such example is Section XI, Nonmandatory Appendix L which provides methods for assessing continued service by ensuring that the component is free of defects and performing a flaw tolerance evaluation. Inspection of the component can then be repeated at the frequency established by the flaw tolerance evaluation and the rules of Appendix L. In this case fatigue is no longer tracked.

14. Environmentally Assisted Fatigue

- Question 14. How to determine the analysis locations when conducting environmentally-assisted fatigue analysis at U.S. nuclear power plants?

- Response 14. The analysis locations selected for environmentally-assisted fatigue (EAF) analysis in the U.S. are a combination of locations that the plant has been tracking as part of their ongoing fatigue monitoring plan (for which they may have made a licensing commitment to monitor) and locations stipulated in the Generic Aging Lessons Learned (GALL) Report. The GALL Report requires licensees to evaluate the locations listed in NUREG/CR-6260, along with any locations that could potentially be more limiting. This ambiguous requirement sometimes means that plants have to screen many more locations than just those listed in NUREG/CR-6260, however NUREG/CR-6260 is the starting point. For later vintage plants that have been designed to Section III of the ASME Boiler and Pressure Vessel Code and have detailed Class 1 fatigue calculations, the number of locations could increase from 6 to over 40 locations.

15. Replacement Modifications

- Question 15. What equipment has been replaced and modified at U.S. nuclear power plants to achieve LR, and is there a list of equipment that has been replaced and modified for a certain pressurized water reactor nuclear power plant?

- Response 15. There is no standardized list of equipment that has been replaced or modified for long term operation. The decision is based on a plant-specific evaluation and long-range capital budgeting. For example, a PWR may determine that a steam generator replacement, reactor vessel head replacement, turbine generator modification, or other major components need to be replaced or upgraded. Another PWR may determine that all of these components are in good condition for another 20+ years and no replacements or modifications are needed.