ENERGY NORTHWEST

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GO2-10-164

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

Subject: **COLUMBIA GENERATING STATION, DOCKET NO. 50-397 RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION LICENSE RENEWAL APPLICATION**

References:
1) Letter, GO2-10-011, dated January 19, 2010, WS Oxenford (Energy Northwest) to NRC, "License Renewal Application"
2) Letter dated August 26, 2010, NRC to SK Gambhir (Energy Northwest), "Request For Additional Information for the Review of the Columbia Generating Station, License Renewal Application for Fatigue Monitoring Program, Time-Limited Aging Analysis Exemptions, Metal Fatigue Time-Limited Aging Analysis, Cumulative Fatigue Damage Cast Austenitic Stainless Steel, and Structural (TAC No ME3058)", (ADAMS Accession No. ML102220373)

Dear Sir or Madam:

By Reference 1, Energy Northwest requested the renewal of the Columbia Generating Station (Columbia) operating license. Via Reference 2, the Nuclear Regulatory Commission (NRC) requested additional information related to the Energy Northwest submittal.

Transmitted herewith in the Attachment is the Energy Northwest response to the Request for Additional Information (RAI) contained in Reference 2. The enclosure contains Amendment 13 to the application submitted in Reference 1. No new commitments are included in this response.

If you have any questions or require additional information, please contact Abbas Mostala at (509) 377-4197.

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NRR

I declare under penalty of perjury that the foregoing is true and correct. Executed on the date of this letter.

Respectfully,

SK Gambhir
Vice President, Technical Services

Attachment: Response to Request for Additional Information

Enclosure: License Renewal Application Amendment 13

cc: NRC Region IV Administrator
NRC NRR Project Manager
NRC Senior Resident Inspector/988C
EJ Leeds - NRC NRR
EFSEC Manager
RN Sherman – BPA/1399
WA Horin – Winston & Strawn
EH Gettys - NRC NRR (w/a)
BE Holian - NRC NRR
RR Cowley – WDOH

**RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION**
"Request for Additional Information for the Review of the Columbia Generating Station, License Renewal Application,"
(ADAMS Accession No. ML102220373)

**RAI B.2.24-02**

**Background**

License renewal application Section B.2.24 identifies the Columbia Fatigue Monitoring Program as an existing plant monitoring program that, with enhancement, will be consistent with the program element criteria in Generic Aging Lessons Learned (GALL) aging management program (AMP) X.M1, "Metal Fatigue of Reactor Coolant Pressure Boundary." The scope of the AMP includes both nuclear steam supply system (NSSS) and non-NSSS components and transients in Updated Final Safety Analysis Report (UFSAR) Section 3.9 that are required to be pursuant to tracking requirements in Technical Specification 5.5.5. The program uses plant transient cycle counting activities to ensure that the cumulative number occurrences (cycles) for each transient will remain below the analyzed number of cycles for the transient, or else to ensure that appropriate corrective action or actions will be taken if the design cycle occurrence limit on a given transient is approached or if the limit on a given component CUF value is approached. AMP B.2.2.4 states that the program will be enhanced to account for the impact of environmental effects on the cumulative usage factor (CUF) values for component locations that are within the scope of the applicant's environmentally-assisted fatigue analysis (refer to LRA Section 4.3.5).

LRA Table 4.3-2 provides the 60-year cycle projections (cycle occurrence projections) for Columbia Generating Station (Columbia) design basis transients.

**Issue**

LRA Section 4.3 indicates that the scope of AMP B.2.24 includes both those transients that are within the scope of UFSAR Section 3.9 and additional transients that are outside the scope of the transients listed in UFSAR Section 3.9. However, LRA Section B.2.24 does not identify which UFSAR Section 3.9 based transients and transients outside of the scope of UFSAR Section 3.9 are within the scope of AMP B.2.24 (i.e. "scope of program" element or the "parameters monitored/inspected" element).

**Request**

Identify all UFSAR-defined and non-UFSAR defined transients (either directly or by reference to transients in applicable sections in LRA Section 4.3 or in UFSAR Sections 3 or 5) that are within the "scope of program" and "parameters monitored/inspected" program elements. Justify any differences between the transients that are within the scope of the program and those that are defined for Columbia in UFSAR Section 3.9 or that are given and analyzed for in LRA Table 4.31 or 4.3-2. Clarify and justify whether or not operational basis earthquake (OBE) transients need to be within the scope of the Fatigue Monitoring Program.

**Energy Northwest Response**

All transients listed in the License Renewal Application (LRA) Table 4.3-1 & FSAR Table 3.9-1 are within the scope of the program with the following exceptions:

1. Daily Reduction to 75% Power -10,000 cycles
2. Weekly Reduction to 50% Power – 2,000 cycles
3. Rod Pattern Change – 400 cycles.

The above cycles are not tracked as part of the fatigue monitoring program for the following reasons:

1. For the boiling water reactor (BWR), the temperature follows the saturation curve such that power reductions are accomplished with little change in bulk vessel temperature. Since the rate of change for both temperature and pressure are very slow and the total temperature change is less than 10°F for most power changes these cycles were not included in the design basis fatigue analyses for the plant.

2. The rod pattern change does not cause a temperature or pressure change for the vessel and attached piping, thus does not impact any design basis fatigue analysis.

The plant experiences dynamic load cycles that were not listed in FSAR Table 3.9-1 and are not in the fatigue monitoring program. These fatigue significant dynamic events are listed in FSAR table 3A.4.1-3. The table lists the following events and cycles:

- OBE- 5 events with 10 equivalent stress cycles per event for 50 total cycles,
- Safety Relief Valve (SRV)- 4,478 events with 3 equivalent stress cycles per event for 13,434 cycles,
- Chugging- 1 event with 1,000 equivalent stress cycles for 1,000 cycles, and
- Safe Shutdown Earthquake (SSE) - 1 event for 10 equivalent cycles for 10 cycles.

The current event count after 27 years of operation is OBE (0), SSE (0), SRV (876), and Chugging (0).

The fatigue monitoring program will be modified to count OBE, SRV, and Chugging events. The SSE event is a faulted condition that is not included in the plant fatigue analyses. Any other transient that is determined to be fatigue significant as a result of updating analyses to account for projected 60 year cycles will be added to the program.

**RAI B.2.24-03**

**Background**

LRA Section B.2.24 identifies the Columbia Fatigue Monitoring Program as an existing plant monitoring program that, with enhancement, will be consistent with the program element criteria in GALL AMP X.M1, "Metal Fatigue of Reactor Coolant Pressure Boundary." The scope of the AMP includes both NSSS and non-NSSS components and transients in UFSAR Section 3.9 that are required to be pursuant to tracking requirements in Technical Specification 5.5.5. The program uses plant transient cycle counting activities to ensure that the cumulative number occurrences (cycles) for each transient will remain below the analyzed number of cycles for the transient, or else to ensure that appropriate corrective action or actions will be taken if the design cycle occurrence limit on a given transient is approached or if the limit on a given component CUF value is approached. AMP B.2.2.4 states that the program will be enhanced to account for the impact of environmental effects on the CUF values for component locations that are within the scope of the applicant's environmentally-assisted fatigue analysis (refer to LRA Section 4.3.5).

LRA Table 4.3-2 provides the 60-year cycle projections (cycle occurrence projections) for Columbia design basis transients.

**Issue**

The transient cycle projection data in LRA Table 4.3-2 indicate the cycle counts for some design basis transients may exceed their design limits prior to the expiration of the period of extended operation or even prior to the expiration of the current operating period. Thus, the relationship of the cycle projection data in LRA Table 4.3-2 and the program elements for AMP B.2.2.4 does not clarify whether corrective actions on the cycle counting limits would need to be implemented as part of the enhance program that will be implemented during the period of extended operation or under the existing program that is being implemented during the current period of operation.

**Request**

For those transients in LRA Table 4.3-2 that are projected to exceed their design basis limits, clarify whether the design basis limit for the transient is projected to be exceeded during the current licensed operating period for the facility or during the period of extended operation. Clarify whether corrective actions on cycle counting will need to be implemented under the existing protocols for the program (i.e., under the program that is currently being implemented for the current licensed operating period) or under the elements of the enhanced program that will be implemented during the period of extended operation. If a cumulative number of occurrences for a given transient are projected to exceed the allowable during the current operating period, clarify whether this has been brought to the attention of the appropriate plant engineering department for potential disposition under the program's existing (current) program element activities and criteria.

**Energy Northwest Response**

The transients in LRA Table 4.3-2 that are projected to exceed their design basis limits within the currently licensed 40 years of operation are reactor startups, reactor shutdowns, and scrams with loss of feedwater pumps. This situation has been brought to the attention of Columbia management and corrective action has been initiated under the existing cycle counting program via the Columbia Corrective Action Program (CAP).

The transient in LRA Table 4.3-2 that is projected to exceed its design basis limit during the period of extended operation is scrams with turbine trip, feedwater on, isolation valves open. Corrective actions for this transient may be either included in the corrective actions initiated under the existing cycle counting program or initiated under the Fatigue Monitoring Program during the period of extended operation (PEO). Any new fatigue analyses done prior to the PEO to incorporate additional heatup/cooldown cycles may also include additional cycles of any transient (such as scram with turbine trip, feedwater on, isolation valves open) that is projected to approach the currently analyzed number of cycles during the PEO. As such, the issue would also be resolved prior to the PEO.

**RAI B.2.24-04**

**Background**

LRA Section B.2.24 identifies the Columbia Fatigue Monitoring Program as an existing plant monitoring program that, with enhancement, will be consistent with the program element criteria in GALL AMP X.M1, "Metal Fatigue of Reactor Coolant Pressure Boundary." The scope of the AMP includes both NSSS and non-NSSS components and transients in UFSAR Section 3.9 that are required to be pursuant to tracking requirements in Technical Specification 5.5.5. The program uses plant transient cycle counting activities to ensure that the cumulative number occurrences (cycles) for each transient will remain below the analyzed number of cycles for the transient, or else to ensure that appropriate corrective action or actions will be taken if the design cycle occurrence limit on a given transient is approached or if the limit on a given component CUF value is approached. AMP B.2.2.4 states that the program will be enhanced to account for the impact of environmental effects on the CUF values for component locations that are within the scope of the applicant's environmentally-assisted fatigue analysis (refer to LRA Section 4.3.5).

LRA Table 4.3-2 provides the 60-year cycle projections (cycle occurrence projections) for Columbia design basis transients.

## Issue

The loading cycles due to OBE at rated operating conditions have been excluded from LRA Table 4.3-3 which gives the analyzed cycles and projected cycles for future analyses. Footnote "d" of LRA Table 4.3-1 states that the OBE event includes 50 peak OBE cycles for NSSS piping and 10 peak OBE cycles for other NSSS equipment and equipment. It further states that 50 peak OBE cycles are postulated for all balance of plant piping and components. This information is also included in relevant subsections of FSAR Section 3.9.1.

## Request

Explain why the loading cycles due to OBE event at rated operating conditions have been excluded from the analyzed cycles and projected cycles for future analyses listed in LRA Table 4.3-3.

## Energy Northwest Response

The change to LRA Table 4.3-2 (Actual Cycles and Projected Cycles), showing that OBE projected cycles remain unchanged, is provided in the enclosure as Amendment 13.

## RAI B.2.24-05

## Background

The "acceptance criteria" program element for AMP B.2.24 is used to ensure that the cumulative number of transient occurrences for a given plant transient will remain below design limit for the transient, as defined in Section 3.9 of the UFSAR, or else that appropriate corrective action will be taken if the limit on transient occurrences or a components CUF value is approached.

## Issue

LRA Section B.2.24 does not provide any details regarding the action limits that are set on design basis transient cycle counting activities or on CUF monitoring activities, or the corrective actions that will be implemented if an action limit of cycle counting or CUF monitoring is reached. The staff has noted that the time-limited aging analysis (TLAA) in LRA Section 4.3 sets the design basis allowable on normal CUF values and environmentally-adjusted CUF values for NUREG/CR-6260 equivalent or bounding locations to a value of 1.0 but sets the design basis allowable for high energy line break locations to a value of 0.1.

**Request**

Identify the "action limits" that are within the scope of the program's "acceptance criteria" program element. Specifically, define the "action limit or limits" that will be used for the program's cycle counting activities and for the program's CUF monitoring activities on: (1) design basis CUF values for Class 1 components and any non-Class 1 components evaluated to Class 1 component CUF requirements,
(2) environmentally-assisted CUF for the program's NUREG/CR-6260 equivalent or bounding locations, and (3) for Class 1 components that are within the scope of the applicant high energy line break analyses for Class 1 components. Clarify those corrective actions that will, with certainty be implemented if an action limit on cycle counting or CUF monitoring is reached, and those additional corrective options that may be implemented in addition to the mandatory corrective actions for the AMP if an action limit on cycle counting or CUF monitoring is reached.

**Energy Northwest Response**

The Columbia Fatigue Monitoring Program as discussed in Appendix B, Section B.2.24, to the LRA does not address action limits because it is compared to the program in NUREG-1801 Section X.M1 “Metal Fatigue of Reactor Coolant Pressure Boundary,” which does not include action limits.

The Columbia Fatigue Monitoring Program counts cycles at least once per year, and then projects those cycles for the remainder of the plant life. If the projection exceeds the number of cycles analyzed in fatigue analyses (design CUF analyses, environmentally assisted fatigue analyses, and high energy line break location analyses), then that condition is entered into Columbia’s CAP.

The CAP will cause the situation to be evaluated in more detail and corrective action will be assigned according to the evaluation. The evaluation could recommend re-evaluation the following year or it could recommend updating fatigue analyses to include additional cycles. If the update of the fatigue analyses is unsuccessful, Columbia would evaluate additional corrective actions such as inspection program or component repair/replacement as discussed in LRA Section B.2.24. This is consistent with NUREG-1801, Section X.M1, Corrective Actions as the Columbia program does not monitor a sample of high usage locations.

The Columbia Fatigue Monitoring Program is based on cycle counting. The Columbia Fatigue Monitoring Program does not monitor nor project CUFs, and as such there is no action limit associated with CUFs. As long as the analyzed number of cycles is not exceeded, the CUFs will not exceed their analyzed values.

## RAI Cumulative Fatigue Damage AMR

### Background

LRA Sections 3.2.2.2.1, 3.3.2.2.1, and 3.4.2.2.1 address cumulative fatigue damage in engineered safety features (ESF) systems, auxiliary (AUX) systems, and steam and power conversion (SPC) systems, respectively. LRA Sections 3.2.2.2.1, 3.3.2.2.1, and 3.4.2.2.1 identify that the TLAA for non-Class 1 components is addressed separately in LRA Section 4.3.4.

The GALL Report includes the aging management review (AMR) items on management of cumulative fatigue damage. Examples of these GALL AMR items are as follows:

- GALL AMR item V.D2-32, for management of cumulative fatigue damage in the piping, piping components and piping elements of the emergency core cooling systems

- GALL AMR items VII.E3-14 and VII.E3-17, for management of cumulative fatigue damage in the piping, piping components, piping elements, and heat exchanger components of the reactor water cleanup system

- GALL AMR item VIII.B2-5 and VIII.D2-6, for management of cumulative fatigue damage in the piping, piping components, piping elements of the main steam and feedwater systems

### Issue

LRA Section 4.3.4 states that the non-Class 1 AMRs for Columbia determined piping locations susceptible to fatigue. The staff noted that none of these locations or components are identified in the LRA and AMR line items. LRA Table 3.2.1 Item 3.2.1-01, LRA Table 3.3.1 Item 3.3.1-02, and LRA Table 3.4.1 Item 3.4-01 identify that cumulative fatigue damage is an aging effect requiring management (AERM) for applicable non-Class 1 piping, piping components, piping elements, and in some cases for applicable heat exchanger components. The staff has noted that, although, LRA Sections 3.2.2.2.1, 3.3.2.2.1, and 3.4.2.2.1, states that fatigue TLAA analyses are required to be evaluated in accordance with 10 CFR 54.21 (c), the LRA does not include any applicable AMR items for non-Class 1 piping, piping components, piping elements, and in some cases for applicable heat exchanger components managed for cumulative fatigue damage.

**Request**

Justify why LRA Tables 3.2.2-1 - 3.2.2-5 for ESF subsystem components, LRA Tables 3.3.2-1 - 3.3.2-44 for AUX subsystem components, and in LRA Tables 3.4.2-1 - 3.4.2-7 for SPC subsystem components do not include any AMR items related to TLAA for managing cumulative fatigue damage in the steel and stainless steel piping, piping components, and piping elements, and possibly in applicable heat exchanger components.

**Energy Northwest Response**

Energy Northwest listed fatigue of Class 1 Components in the 3.1.2-X tables because fatigue of Class 1 components is managed by the Fatigue Monitoring Program as stated in LRA Sections 4.3.1, 4.3.2, and 4.3.3, even though for consistency with NUREG-1801, TLAA appears in the Aging Management Program column.

Energy Northwest opted not to list fatigue of non-Class 1 components in the Section 3.2, 3.3, and 3.4 tables because this aging effect is not managed by a program. As stated in LRA Section 4.3.4, all non-Class 1 components were reviewed as part of the Aging Management Review process. No specific detailed fatigue analysis was required as part of the original design for the non-Class 1 components. ASME Class 2 and 3 piping does not include evaluation of all cyclic loads such as pressure, moments, and pipe wall temperature gradients. Rather the simplified fatigue analysis for Class 2 and 3 piping only addresses cyclic moment range by evaluating thermal moment range. The cyclic evaluation is accomplished by utilization of a stress range reduction factor. The factor utilized in Energy Northwest analyses was for 7000 cycles of the full moment range. These non-Class 1 fatigue analyses remain valid through the extended period of operation because none of the Columbia systems will reach the analyzed 7000 full range expansion cycles. There is no implicit/explicit fatigue analysis and, hence, no fatigue aging effect for non-Class 1 heat exchangers, vessels, tanks, and pumps. In either case there is no fatigue managed by a NUREG-1801 program.

**RAI 4.1-1**

**Background**

LRA Section 4.1.3 states that pursuant to 10 CFR 54.21 (c)(2), an applicant for license renewal must provide: (1) a listing of plant-specific exemptions granted to 10 CFR 50.12 that are in effect and based on a TLAA, and (2) an evaluation of these exemptions to justify their continuation for the period of extended operation. The applicant stated that the current licensing basis documentation, identified in Section 4.1.1, was reviewed and there were no exemptions identified that are based on a TLAA.

## Issue

Columbia facility operating license, No. NPF-21, issued December 20, 1993, states in part, "Exemptions from certain requirements of Appendices G, H, and J to 10 CFR Part 50, are described in the Safety Evaluation Report. These exemptions are authorized by law and will not endanger life or property or the common defense and security and are otherwise in the public interest. Therefore these exemptions are hereby granted pursuant to 10 CFR 50.12. With the granting of this exemption the facility will operate, to the extent authorized herein, in conformity with the application, as amended, the provisions of the Act, and the rules and regulations of the Commission." The staff is unable to determine if exemptions to the requirements of Appendices G, H, and J to 10 CFR Part 50 exist or whether these exemptions are still in effect and are based on a TLAA that will be needed for the period of extended operation.

## Request

Clarify the exemptions to the requirements of Appendices G, H, and J to 10 CFR Part 50 and clarify whether these exemptions are still in effect and whether they are based on a TLAA. If they are in effect and based on a TLAA, justify continuation of the exemptions for the period of extended operation.

## Energy Northwest Response

The exemptions to Appendices G, H, and J to 10 CFR 50 are still in effect, but are not based on TLAA. Each exemption is summarized below:

Appendix G:

(1) Paragraph III.B.1, Appendix G: The applicant did not take the Charpy V-notch (CVN) test specimens representing the reactor pressure vessel perpendicular to the major rolling (transverse) direction. The CVN tests conducted for the Columbia pressure vessel base metal were performed using longitudinally oriented specimens. The staff concluded that data obtained using longitudinally oriented specimens could be translated to an equivalent transverse CVN impact energy for comparison with the requirements of Appendix G.

(2) Paragraph III.B.3, Appendix G: The temperature instruments and the CVN test machines were not calibrated in accordance with Paragraph NB-2360 of Section III of the ASME Code, since verification of the required calibration was not possible. GE stated that the test instruments and machines were routinely calibrated on a periodic basis. Based on the standard practice of the period and on past experience with Charpy testing, the staff concluded that it was very unlikely that test instruments and machines were not adequately calibrated.

(3) Paragraph III.B.4, Appendix G: The testing personnel were not tested in accordance with written procedures as required. However, the individuals were qualified by on-the-job training and past experience, with the tests being relatively routine in nature and continually performed in the laboratory conducting the tests.

(4) Paragraph III.C.2, Appendix G: The Columbia weld material test specimens were not taken from excess beltline material. The weld wire and flux materials used in the test specimens are the same as those used in the reactor vessel beltline. The staff concluded that the use of weldment test specimens having the same weld wire, flux, welding process, and heat treatment as the beltline welds was sufficient to satisfy the intent of Paragraph III.C.2.

(5) Paragraph IV.A.3, Appendix G: The Columbia main steam isolation valve (MSIV) discs, covers, and bodies were not CVN impact tested (per Paragraph NB-2330 of the ASME Code). However, the staff concluded that this testing was not necessary because CVN impact data was provided, from literature and other nuclear plants on material equivalent to the Columbia MSIV discs, covers, and bodies, that demonstrated the Columbia material would have met the requirements of Paragraph IV.A.3, had it been tested.

Exemptions 1 through 4 are related to the determination of the initial properties (upper shelf energy, reference temperature for nil-ductility transition) for the Columbia reactor vessel. These exemptions and their justifications in the SER, have no time related parameters. As such, these exemptions are not based on TLAA and need not be reported for License Renewal. Since the issuance of this license, the initial parameters for the Columbia reactor vessel have been refined, and continue to be refined, based largely on the integrated surveillance program for all BWR reactors. Thus, the best possible parameters are currently being used for the neutron embrittlement TLAA for license renewal.

Exemption 5 pertains to the fracture toughness testing of material for the main steam isolation valves as required by Paragraph IV.A.3 of Appendix G. Testing of the Columbia material was not performed as the material was purchased to an earlier Code edition that did not require testing. There are no time related aspects to this exemption or its approval, and therefore there is no TLAA for license renewal.

Appendix H:

The exemption to Appendix H to 10 CFR 50 discussed in the original Columbia SER is that the most limiting beltline material per ASTM E 185-73 (the material with the highest adjusted reference temperature) has not been included in the Columbia surveillance program. Also, the plate surveillance CVN specimens were taken from the longitudinal direction and not the transverse direction as required by ASTM E 185-73.

The SER concluded that the surveillance specimens, while not from the limiting material, were adequate to allow the staff to use Regulatory Guide (RG) 1.99, Rev. 2 to project the embrittlement of the most limiting weld/plate. The specimens being taken in the longitudinal direction instead of the transverse direction has no time related dependencies and is thus not a TLAA. The SER concluded that the surveillance specimens were adequate to allow the staff to use RG 1.99, Rev. 2 to project the embrittlement of the most limiting weld/plate. This is true today as the Integrated Surveillance Program provides more surveillance data for refined projections.

Appendix J:

The exemption to Appendix J to 10 CFR 50 (Paragraphs III.C.2 and III.C.3) discussed in the original Columbia SER involve leak rate testing of the main steam line isolation valves. The SER discussion states, "The design of the main steam isolation valves is such that testing in the reverse direction tends to unseat the valve. Testing of the two valves simultaneously, between the valves, at design pressure, would lift the disc at the inboard valve. This would result in a meaningless test. The proposed test calls for a test pressure of 25.0 psig to avoid lifting the disc at the inboard valve. The total observed leakage through both valves (inboard and outboard) is then conservatively assigned to the penetration. The staff concludes that this procedure is acceptable. Furthermore, excluding the leakage from the summation for the local leak rate tests is acceptable because the leakage has been accounted for separately in the radiological analysis of the site." There are no time related aspects to this exemption or its approval, and therefore there is no TLAA for license renewal.

## RAI 4.3-01

### Background

LRA Table 4.3-3 provides the design basis CUF values of record for the limiting reactor pressure vessel (RPV) locations. UFSAR Section 3.9 and UFSAR Table 3.9-2a provides the UFSAR design basis CUFs for these component locations.

**Issue**

The staff has noted that some of these CUF values reported for RPV components in LRA Table 4.3-3 are consistent with those listed for the components in Columbia UFSAR Table 3.9-2a and some are not. The staff has noted that the CUF value listed for feedwater (FW) nozzle safe end in LRA Table 4.3-3 is 0.696 while the UFSAR Table 3.9-2a lists the value as 0.966. It is not clear if some of the CUF of record have been reanalyzed, and if they were, it is not clear whether lower CUF were obtained by decreasing the projected number of load cycles and/or decreasing the severity of the transient. Also, if severity of the transient were decreased, it is not clear whether the revised transients were verified by plant-specific stress-based fatigue monitoring.

**Request**

Provide your basis why LRA Table 4.3-3 lists a different CUF value for the FW nozzle safe end from that reported for the component in UFSAR Table 3.9-2a. Specifically, justify why the CUF value listed for the FW nozzle safe end in LRA Table 4.3-3 is 0.696 while the UFSAR Table 3.9-2a lists the value as 0.966. If the CUF value listed for the FW nozzle in LRA Table 4.3-3 represents the most updated design basis value for the component, reference the document in the CLB that provides the design basis CUF of record for the FW nozzle component and clarify the changes in the CUF calculation assumptions or bases that resulted in a 0.27 drop in the design basis CUF value for the components (i. e. from a value of 0.966 to a value 0.696).

**Energy Northwest Response**

The FW nozzle safe end CUF in FSAR table 3.9-2a was corrected in Amendment 61 of the FSAR to be 0.696 and match the value in LRA Table 4.3-3.

**RAI 4.3-02**

**Background**

Several Boiling Water Reactor Vessel Internals Project (BWRVIP) documents credited for Columbia license renewal have NRC safety evaluation reports (SERs) with associated license renewal applicant action items (AAIs). The applicant provides a plant-specific response for each of these AAIs is provided in Appendix C of the LRA. The applicant's response to AAI No. 4 from BWRVIP-47-A; BWR Lower Plenum Inspection and Flaw Evaluation Guidelines states, "Due to fatigue of the subject safety-related components, applicants referencing the BWRVIP-47 report for LR should identify and evaluate the projected CUF as a potential TLAA issue." In LRA Table C-4, the applicant also states that the TLAAs identified for the lower plenum are the CUF analyses and results for the control rod drive (CRD) housings, CRD stub tubes, and incore housing penetrations, and that these are addressed in LRA Section 4.3.1 (Table 4.3-3).

**Issue**

The staff confirmed that the CUF values for the CRD housings and CRD stub tubes are included in the fatigue analyses of the RPV components and the values are listed in LRA Table 4.3-3. However, neither LRA Table 4.3-3 nor LRA Table 4.3-4 provides any CUF value for the incore housing penetrations.

**Request**

Clarify whether the CUF value for stub tubes listed in LRA Table 4.3-3 is the CUF value that is identified in the LRA for incore housings. If CUF value in LRA Table 4.3-3 for the stub tubes is not the CUF value for the incore housings, identify what the design basis CUF value of record is for the incore housing penetrations and reference the design basis document of record that provides the design CUF value for this component.

**Energy Northwest Response**

The CUF value listed in LRA Table 4.3-3 for the CRD stub tube is not the CUF value for the incore housings. The CUF value for the incore housings was not listed in LRA Table 4.3-3, because the CUF of the incore housings was not considered to be a TLAA for Columbia, as described below.

The original equipment manufacturer (OEM) stress report for the Columbia reactor vessel calculated a CUF for the CRD penetrations. The OEM stress report for the Columbia reactor vessel did not calculate a CUF for the incore housing penetrations. There is a generic stress report for these penetrations; however, as this is a generic analysis and not a Columbia-specific analysis, it is not considered a Columbia CUF of record and thus is not a Columbia TLAA.

Energy Northwest listed the generic incore penetration CUF in earlier versions of the basis documents upon which the LRA was based, but deleted it because it was not a plant specific analysis. Unfortunately, reference to the CUF for the incore housing penetrations was not also deleted from Appendix C, Table C-8. Appendix C, Table C-8 is amended in response to this RAI to correct this oversight.

**RAI 4.3-03**

**Background**

LRA Section 4.3.2.2 states that in August 2000, Columbia operated for a period of time with the recirculation pumps in an unbalanced mode (i.e., the running speeds for the pumps differed by more than 50%). The LRA states that the effect of the flow imbalance resulted in a 0.0035 increase in the CUF value for the plant's jet pumps. The LRA also indicates that inspections of the jet pumps in 2001 identified gaps in the jet pump set screws, and that a fatigue analysis of the jet pump risers through operations as of end of cycle 16 indicated an additional 0.119 increase in the CUF value for jet pumps 1 and 6 (including risers 1 and 2 for jet pump 1 and risers 5 and 6 for jet pump 6) due to the gaps in the component configuration. In addition, the LRA indicates that in 2005, the applicant installed clamps on the jet pump mixer and diffuser areas in order to minimize flow-induced vibrations caused by leakage at the mixer-to-diffuser slip joint interface.

LRA Section 4.3.2.2 credits the cycle counting activities to disposition the CUF TLAA for the jet pump assemblies in accordance 10 CFR 54.21 (c )(1)(iii). In LRA Section 4.3.2.2, the applicant states that Columbia uses the BWRVIP to inspect for cracking and gaps (changes in configuration) in applicable jet pump assembly components.

**Issue**

The Columbia Reactor Vessel Internals Program includes inspections of jet pump assembly components consistent with the inspection criteria of Report BWRVIP-41. The scope of inspections in BWRVIP-41 includes inspections of the jet pump risers, riser braces, and mixers for cracking and changes in configuration (including set screw gaps in applicable jet pump components). LRA Section 4.3.2.2 already states that the Columbia Reactor Vessel Internals Program is credited with inspections of the applicable jet pump assembly components.

**Request**

Provide your basis for using cycle counting under the Metal Fatigue of Reactor Coolant Pressure Boundary Program to disposition the CUF value for the jet pump assembly components, and why it would not be more appropriate to credit the inspections of the jet pump assembly components under Columbia Reactor Vessel Internals Programs as the basis for dispositioning the TLAA for these components and for managing cumulative fatigue damage/cracking by fatigue in these components in accordance with 10 CFR 54.21(c)(1)(iii).

**Energy Northwest Response**

As described in LRA Section 4.3.2.2, the jet pump fatigue analysis depends on two components: 1) the number of thermal cycles incurred, and 2) the jet pump gaps. The basis for managing the fatigue usage of the jet pumps uses the Fatigue Monitoring Program to track transient cycles with input from the BWR Vessel Internals Program to monitors jet pump gaps. As stated in LRA Section 4.3.2.2, "The Fatigue Monitoring Program will also monitor the occurrence of design cycles and will monitor the jet pump gaps, effectively managing the fatigue of the jet pumps through the period of extended operation."

It is more appropriate to credit the Fatigue Monitoring Program (which incorporates the BWR Vessel Internals Program to measure the jet pump gaps) for managing cumulative fatigue damage/cracking by fatigue in the jet pump risers because, as described in LRA Section 4.3.2.2, the majority of the fatigue usage comes from transient cycles rather than jet pump gaps. The CUF for risers 1/2 and 5/6 consists of 0.75 due to transients and only 0.12 due to gaps. For the other eight risers there is no contribution from gaps. As stated in LRA Section 4.3.2.2 and again in Appendix B, Section B.2.24 (Fatigue Monitoring Program), the Fatigue Monitoring Program not only counts cycles but also incorporates the BWR Vessel Internals Program to ensure that the jet pump gaps remain below the analyzed gap.

**RAI 4.3-04**

**Background**

The UFSAR Table 3.9-1 lists the design basis transients and design limits for these transients that are applicable to the Columbia NSSS components (including RPV assembly components, core support/RPV internal components, and Class 1 reactor coolant pressure boundary piping components) and to non-NSSS (balance of plant) components, with the those for the CRDs and the CRD housings and incore housings.

UFSAR Section 3.9.1.1 provides the design basis transients that are applicable to the CRDs and design limits for these transients, and UFSAR Section 3.9.1.2 provides the design transients that are applicable to the CRD housings and incore housings.

**Issue**

The staff confirmed that LRA Tables 4.3-1 and 4.3-1 accurately reflect the design basis transients that are listed in UFSAR Table 3.9-1 as being applicable to the NSSS components and non-NSSS components, and design limits for these transients. However, the staff has noted that the LRA does not give corresponding tables for the transients and design limits that are applicable to the CRD nozzles and to the CRD housings and incore housings, as given in UFSAR Sections 3.9.1.1 and 3.9.1.2, respectively.

**Request**

For the NSSS and non-NSSS components that were included in LRA Tables 4.3-1 and 4.3-2, as based on the design basis transients and design limits for the transients in UFSAR Table 3.9-1.

1. Provide your basis for not including design basis transient cycle and 60-year design basis cycle projection tables in LRA Section 4.3 for the CRDs that are based on the design basis transients and design limits for these transients in UFSAR Section 3.9.1.1.1.

2. Provide your basis for not including design basis transient cycle and 60-year design basis cycle projection tables in LRA Section 4.3 for the CRD housings and incore housings that are based on the design basis transients and design limits for these transients in UFSAR Section 3.9.1.1.2.

## Energy Northwest Response

The CUFs of record related to the Columbia CRDs are the 0.083 for the stub tube and the 0.196 for the housing given in LRA Table 4.3-3. These CUFs are from the OEM stress report for the reactor vessel and are based on the design transients in LRA Table 4.3-1 (FSAR Table 3.9-1).

1. The design basis transient cycles listed in FSAR Section 3.9.1.1.1 were used by the OEM for a generic analysis of the CRDs. This analysis is not a Columbia-specific analysis and therefore is not considered a Columbia TLAA. As such, the cycles in FSAR 3.9.1.1.1 do not require extrapolation to 60 years.

   The transients in FSAR Section 3.9.1.1.2 were used by the OEM for a generic analysis of the CRD housing. This is not a Columbia-specific analysis and The CUF of record are the Columbia-specific CUFs for the stub tube and housing calculated by the reactor vessel OEM in the reactor vessel stress report. The CUF of record for the CRD housing is 0.196 as presented in LRA Table 4.3-3. This value is based on the design transients in LRA Table 4.3-1 (FSAR Table 3.9-1).

2. The transients in FSAR Section 3.9.1.1.2 were used by the OEM for a generic analysis of the incore housings. This analysis is not a Columbia-specific analysis and therefore is not considered a Columbia TLAA. As such, the cycles in FSAR 3.9.1.1.2 do not require extrapolation to 60 years.

## RAI 4.3-05

## Background

LRA Section 4.3.5 summarizes the evaluation of the CUF analyses that comprise the "Effects of Reactor Coolant Environment on Fatigue Life of Components and Piping," for the period of extended operation. The applicant stated that although environmentally-assisted fatigue evaluations are not part of the existing design basis, these evaluations were performed for the 60-year operation period using the projected cycles from the Fatigue Monitoring Program, and the methodology described in Standard Review Plan-License Renewal (SRP-LR) Sections 4.3.2.2 and 4.3.3.2. The applicant further stated that the original fatigue usage calculations were reviewed, and the transient groupings and load pairs used in those analyses were carried over to the environmentally-assisted fatigue analyses. The applicant added that for each load pair, an environmental correction factor ($F_{en}$) was calculated, and environmentally-assisted CUF factor for the load pair was obtained by multiplying the design basis CUF factor for the component factor by $F_{en}$ factor that was determined for the component. The environmentally assisted CUF for the location was obtained by summing the individual environmentally assisted usage factors for each load pair. The environmentally assisted CUF and the minimum and maximum $F_{en}$ for any load pair for the 14 locations in six components are shown in Table 4.3-6.

## Issue

The design basis "CUF in air" values listed for the limiting environmental fatigue components in LRA Table 4.3-6 are different from and usually lower than the design basis CUF values listed for the same component in either LRA Table 4.3-3 or 4.3-5. Specifically, LRA Table 4.3-6 Footnote 2 states that the "Revised CUF in air" value for the component in LRA Table 4.3-6 is the "CUF of record previously identified in Table 4.3-3 and Table 4.3-5." This implies that the design basis CUF value listed in LRA Table 4.3-6 for a given component should be exactly the same as the design basis CUF value that is reported for the component in either LRA Table 4.3-3 or 4.3-5.

## Request

For each component location listed in LRA Table 4.3-6, provide the basis why LRA Table 4.3-6 reports design basis CUF values for the component locations that are different from (and are usually lower than) the CUF values reported for the component locations in either LRA Table 4.3-3 or 4.3-5, particularly when Footnote 2 states that the "Revised CUF in air" value for the component in LRA Table 4.3-6 is the "CUF of record previously identified in Table 4.3-3 and Table 4.3-5." For each environmentally-assisted fatigue location given in LRA Table 4.3-6, clarify which design basis CUF value for each of components (i.e., the value as reported in Table 4.3-3 or 4.3-5 or the value reported in LRA Table 4.3-6) is the design basis value of record for component and reference the Columbia document of record that establishes the value as the current design basis CUF value for the component. Clarify that changes that were made in the CUF calculation for a component if the design basis CUF value reported in LRA Table 4.3-6 represents the most up-to-date design basis value of record.

## Energy Northwest Response

Tables 4.3-3 and 4.3-5 list the Maximum CUF found for each of the listed Reactor Vessel locations or piping systems as found in the calculations of record prior to any reanalysis activity to evaluate the effects of reactor water environment.

Table 4.3.6 column labeled "Revised CUF in air" will be clarified to explain that it includes the computed CUF in air for the wetted surface of interest for the evaluation of reactor water environment on the component. This change to the LRA is provided in the enclosure as Amendment 13.

There are a number of reasons that the values in the referenced tables are different. The starting in air usage factors in Table 4.3.6 includes the following changes or refinements that were implemented prior to determining environmental fatigue life penalty factors. A summary of changes is provided below:

- The usage factors listed in table 4.3-6 reflect the projected plant cycles for 60 years of operation. This included additional startup/shutdown cycles, reduced bolt up / un-bolt cycles, reduced vessel hydro test cycles, increased turbine generator scram cycles with feedwater on, and reduced cycles for other scrams. While some cycles have increased, such as startup/shutdown they tend to cause very low thermal transient stresses and thus do not significantly impact fatigue usage.

- The location for environmental fatigue usage determination must be on a wetted surface. The maximum usage locations reported in Tables 4.3-3 and 4.3-5 are not necessarily on the inside wetted surface.

- In order to gain margin in the "in air" usage prior to applying the $F_{en}$, conservatisms in the design analyses of record were removed. This included regrouping of conservative load pairs, taking credit for hardware changes during construction that were previously not credited in the analyses, replacing original enveloping design transients with current Design Specification transients, and finally reducing conservative stress concentration penalties.

Each of the components listed in Table 4.3-6 was assessed prior to applying the environmental fatigue penalty. A detailed list is provided below for each entry to explain in general what factors contribute to a difference between the CUF of record and the calculated CUF in air for use in environmental fatigue analyses.

| NUREG/CR 6260 Location | | Columbia Plant Specific Location | 40-year CUF of Record | 60-year Optimized CUF | Basis for Difference |
|---|---|---|---|---|---|
| 1 | Reactor vessel shell and lower head | CRD stub tube | 0.083 | 0.0125 | Note 1<br>Note 2 |
| 1 | Reactor vessel shell and lower head | CRD housing | 0.196 | 0.0007 | Note 1<br>Note 2 |
| 2 | Reactor Vessel Feedwater Nozzle | FW nozzle to shell junction | 0.650 | 0.132 | Note 2<br>Note 3 |
| 2 | Reactor Vessel Feedwater Nozzle | FW nozzle safe end | 0.696 | 0.00126 | Note 2<br>Note 3 |
| 3 | Reactor Recirculation piping including inlet and outlet nozzles. | RRC inlet nozzle safe end | 0.214 | 0.026 | Note 1<br>Note 2<br>Note 4 |
| 3 | Reactor Recirculation piping including inlet and outlet nozzles. | RRC outlet Nozzle forging | 0.24 | 0.054 | Note 1<br>Note 2 |
| 3 | Reactor Recirculation piping including inlet and outlet nozzles. | RRC piping. | 0.920 and 0.850 | 0.373 | Note 2<br>Note 5 |
| 4 | Core Spray line reactor vessel nozzle and associated Class 1 Piping | Reactor Vessel nozzle safe end Core Spray | 0.801 | 0.241 | Note 1<br>Note 2<br>Note 6 |

| NUREG/CR 6260 Location | | Columbia Plant Specific Location | 40-year CUF of Record | 60-year Optimized CUF | Basis for Difference |
|---|---|---|---|---|---|
| 4 | Core Spray line reactor vessel nozzle and associated Class 1 Piping | LPCS Piping | 0.145 | 0.155 | Note 2 |
| 4 | Core Spray line reactor vessel nozzle and associated Class 1 Piping | HPCS piping | 0.237 | 0.321 | Note 2 |
| 5 | Residual Heat Removal (RHR) nozzles and associate Class 1 piping | RHR/LPCI Nozzle | 0.157 | 0.139 | Note 2<br>Note 7 |
| 5 | Residual Heat Removal (RHR) nozzles and associate Class 1 piping | RHR/LPCI nozzle safe end extension | 0.189 | 0.190 | Note 2 |
| 5 | Residual Heat Removal (RHR) nozzles and associate Class 1 piping | RHR /LPCI Piping | 0.001 | 0.001 | Note 2 |
| 6 | Feedwater line Class 1 piping | RFW/RWCU Tee | 0.588 | 0.210 | Note 2<br>Note 8 |

*Notes:*

1. *Maximum usage of record was on a non-wetted surface. Environmental location was on a wetted surface.*
2. *Transient cycles utilized for environmental fatigue were the projected 60 year cycles.*
3. *Feedwater thermal transients, updated in a 1990 revision to the plant Design Specification, that reflect more correctly reflect the actual plant operation were utilized to reduce the conservatism in the original RPV feedwater nozzle thermal transient definitions.*
4. *The RRC inlet nozzle welded thermal sleeves were replaced with a tuning fork design just prior to plant startup. The CUF of record did not take credit for the reduced Stress Concentration Factor that was documented by the NSSS supplier in a supplemental Design Report. This updated document was credited in the environmental fatigue analyses.*
5. *The usage factors for both loops of the RRC piping were very low, less than .1, with one exception at the same location on each loop. The high usage came from a dynamic load pair that would have had a strain rate above the strain threshold for $F_{en}$. The NSSS supplier reviewed the analyses and revised the load combination from an absolute sum to an SRSS consistent with other analyses for Columbia. This reduced the usage to 0.288 for 40 years.*
6. *The original thermal transient that utilized a step temperature change was modified to account for the time to flush warmer water prior to the injection of the lowest projected temperature water.*
7. *Although cycles for startups/shutdowns increased, the total scram cycles were reduced. Thus, for this nozzle the increase in usage due to more cycles of the minor transients were offset by reduced cycles of major transients.*

8. *Conservative lumping of transients was eliminated and the stress indices for the piping location were corrected to reflect the installed weld configuration.*

**RAI 4.3-06**

**Background**

The design load cycles used in the fatigue analyses of reactor vessel internals are the same as those for RPV components. The design load cycles are listed in LRA Table 4.3-1 and the projected cycles to 60 years are presented in LRA Table 4.3-2. In addition, the CUFs for the limiting reactor vessel support structures and vessel internals are summarized in LRA Table 4.3-4. These CUF values, except for the jet pump riser brace, are based on the original design cycles for 40-year operation. The CUF for the jet pump riser brace has been conservatively projected to 60-year operation.

**Issue**

The staff has noted that the Columbia environmentally-assisted fatigue analysis does not always apply the NUREG/CR-6260 methodology to the RPV or Class 1 piping components that have the highest design basis CUF values of record. For example, in the environmental assessment in LRA Table 4.3-6 identifies that the CRD tube and CRD housing were selected as the representative locations for the RPV shell and lower head, and that the design basis CUF values for these component locations were 0.083 and 0.196, respectively. However, LRA Table 4.3-3 lists the shroud support (0.399), main steam nozzle shell (0.47), or low-pressure coolant injection (LPCI) thermal sleeve (0.430) as all have existing design basis CUF values that are greater than those reported for the CRD tubes and CRD housings in LRA Table 4.3-3.

**Request**

Provide your basis for selecting the RPV and Class 1 piping locations that were chosen as the environmentally-assisted fatigue analysis locations for the LRA, as given in LRA Table 4.3-6. Provide your basis for not selecting the core shroud supports, main stem shell nozzles, and LPCI nozzle thermal sleeves as additional environmentally-assisted fatigue assessment locations.

**Energy Northwest Response**

The Energy Northwest bases for selecting the locations for an environmentally-assisted fatigue analysis, as listed in LRA Table 4.3-6, are provided below:

1. NUREG-1801, Section X.M1 says the applicant "addresses the effects of the coolant environment on component fatigue life by assessing the impact of the reactor coolant environment on a sample of critical components for the plant."

2. Sample components are identified in NUREG/CR-6260, which states in Section 4.1, "For both PWR and BWR plants, these components are not necessarily the locations with the highest design CUFs in the plant, but were chosen to give a representative overview of components that had higher CUFs and/or were important from a risk perspective." Energy Northwest analyzed 14 site-specific locations that represent the six locations identified in NUREG/CR-6260 for a BWR of Columbia's vintage. The 14 analyzed locations contain all the different materials (carbon steel, low-alloy steel, stainless steel, and nickel-alloy) used in the Columbia reactor vessel and attached piping.

3. The position defined above is consistent with recent LRAs approved by the NRC, indicating that analyses of site-specific locations representative of the six NUREG-6260 locations is an adequate sample to assess the impact of the reactor coolant environment on fatigue.

4. The core shroud supports are not reactor coolant pressure boundary components and were not included in the six locations identified in NUREG/CR-6260 for a BWR of Columbia's vintage.

5. The main steam shell nozzles are exposed to dry steam. The environmental $F_{en}$ factors apply to components exposed to reactor coolant. The factors do not apply to surfaces exposed to gaseous environments such as dry steam. Thus, Energy Northwest determined that it was not appropriate to apply the factors to the main steam shell nozzles.

6. The high usage location on the LPCI nozzle thermal sleeve was not evaluated because it was located on the thermal sleeve extension within the RPV nozzle in a non-pressure boundary portion of the sleeve.

Energy Northwest did not select the core shroud supports, main steam shell nozzles, or the LPCI nozzle thermal sleeves as additional environmentally-assisted fatigue assessment locations because NUREG/CR-6260 did not identify these locations as necessary to give a representative overview.

## RAI 4.3-07

### Background

LRA Section 4.3.5 indicates that an effective $F_{en}$ methodology that is based on a time-weighted average of normal water chemistry (NWC) and hydrogen water chemistry (HWC) operations over a cumulative 60 year operating period (i.e., 20.9 years at NWC and 39.1 years and HWC, respectively) was used to determine environmentally assisted $F_{en}$ factors that were used in the environmentally-assisted fatigue calculations (i.e. for the environmental CUF calculations). A footnote in LRA Table 4.3-6 indicates that the dissolved oxygen in the FW nozzle safe end and nozzle to shell junction locations was assumed to be 150 ppb.

### Issue

According to BWRVIP-130 "BWR Vessel and Internals Project BWR Water Chemistry Guidelines - 2004 Revision," the operating range for dissolved oxygen is 30-200 ppb for NWC and 30-100 ppb for HWC. However, LRA Section 4.3.5 does not give any details regarding the dissolved oxygen concentration values for implementation of NWC and HWC conditions that were derived and applied to the $F_{en}$ calculation methodology, or the basis for deriving the dissolved oxygen values.

### Request

For each component location listed in LRA Table 4.3-6 (other than the FW nozzle), provide the dissolved oxygen concentration inputs under implementation of NWC and HWC operating conditions that were used in the calculation of the $F_{en}$ values for the components, and clarify how these dissolved oxygen inputs were derived and why they are considered to be conservative for application to the $F_{en}$ methodology.

### Energy Northwest Response

Plant specific operating chemistry data at Columbia showed that the average reactor water operating NWC and HWC dissolved oxygen concentrations in the reactor pressure vessel shell and upper head regions and recirculation piping were 87 parts per billion (ppb) and 1 ppb, respectively. In the reactor vessel lower head region, the average operating NWC and HWC dissolved oxygen concentrations are 153 ppb and 1 ppb, respectively. At locations exposed to air saturated water environments a bounding dissolved oxygen concentration 500 ppb was assumed.

The operating NWC and HWC dissolved oxygen concentration inputs used in the $F_{en}$ calculations for the component locations identified in LRA Table 4.3-6 are summarized in the table below.

| NUREG/CR-6260 Generic Locations | | Columbia Plant-specific Locations | Material Type | Normal Water Chemistry DO (ppb) | Hydrogen Water Chemistry DO (ppb) |
|---|---|---|---|---|---|
| 1 | Reactor vessel shell and lower head | CRD stub tube | Nickel Alloy | ≥50 | < 50 |
| 1 | Reactor vessel shell and lower head | CRD housing | SS | ≥50 | <50 |
| 2 | Reactor vessel feedwater nozzle | FW nozzle to shell junction | LAS | 150 | 40(3) |
| 2 | Reactor vessel feedwater nozzle | FW nozzle safe end | Nickel Alloy | >50 | >50 |
| 3 | Reactor recirculation piping (including inlet and outlet nozzles) | Reactor vessel RRC inlet nozzle safe end | SS | ≥50 | <50 |
| 3 | Reactor recirculation piping (including inlet and outlet nozzles) | Reactor vessel RRC outlet nozzle forging | LAS | 200 | <40 |
| 3 | Reactor recirculation piping (including inlet and outlet nozzles) | RRC piping | SS | ≥50 | <50 |
| 4 | Core spray line reactor vessel nozzle and associated Class 1 piping | Reactor vessel nozzle safe end – Core Spray | Nickel Alloy | ≥50 | <50 |
| 4 | Core spray line reactor vessel nozzle and associated Class 1 piping | LPCS piping | CS | 500 (2) | N/A |
| 4 | Core spray line reactor vessel nozzle and associated Class 1 piping | HPCS piping | CS | 500(2) | N/A |
| 5 | Residual Heat Removal (RHR) nozzles and associated Class 1 piping | RHR/LPCI nozzle safe end | Nickel Alloy | ≥50 | <50 |
| 5 | Residual Heat Removal (RHR) nozzles and associated Class 1 piping | RHR/LPCI nozzle safe end extension | CS | 200 | <40 |
| 5 | Residual Heat Removal (RHR) nozzles and associated Class 1 piping | RHR/LPCI piping | CS | 500 (2) | N/A |
| 6 | Feedwater line Class 1 piping | RFW/RWCU Tee (1) | CS | 150 | <40 |

Notes:

1. *At this tee connection RWCU return water from the lower head region (153 ppb NWC and 1 ppb HWC) mixes with feedwater having an average operating NWC and HWC dissolved oxygen concentrations of the feedwater are 58 ppb and 54 ppb respectively. Since the root of the weld is expected to see some mixture of these two conditions, the $F_{en}$ calculations assumed 150 ppb and 40 ppb dissolved oxygen concentrations for NWC and HWC respectively.*

2. *These locations are subjected to air saturated water environments from the Suppression Pool and/or the Condensate Storage Tank during thermal transient fatigue loading.*

3. *The feedwater nozzle thermal sleeve is welded directly to the sparger tee. Feedwater flow goes through the thermal sleeve directly into the sparger and is delivered to the vessel via a series of holes in the sparger. The sparger holes direct the water away from the vessel wall. Bulk reactor water dissolved oxygen (DO) is 1ppb (HWC). For conservatism it was assumed that some mixing of the feedwater at 54 ppb occurs with the bulk reactor water at 1ppb. Therefore, a value of 40 ppb was used for the DO at the blend radius of the feedwater nozzle.*

**RAI 4.3-08**

**Background**

LRA Section 4.3.5 indicates that an effective $F_{en}$ methodology that is based on a time-weighted average of NWC and HWC operations over a cumulative 60 year operating period (i.e., 20.9 years at NWC and 39.1 years and HWC, respectively) was used to determine environmentally assisted $F_{en}$ factors that were used in the environmentally-assisted fatigue calculations (i.e., for the environmental CUF calculations). A footnote in LRA Table 4.3-6 indicates that the dissolved oxygen in the FW nozzle safe end and nozzle to shell junction locations was assumed to be 150 ppb.

**Issue**

The LRA does not provide the basis for assuming a 150 ppb dissolved oxygen concentration value for the FW nozzle. The staff presumes that the 150 ppb dissolved oxygen concentration value for the FW nozzle is the value under implementation of NWC; however, this is not specifically evident from the contents of the LRA.

**Request**

Justify your basis for assuming a 150 ppb dissolved oxygen concentration value for the FW nozzles and clarify whether this value represents the value for operations under NWC conditions or HWC conditions.

**Energy Northwest Response**

The operating NWC and HWC dissolved oxygen concentration inputs used in the $F_{en}$ calculations for the component locations identified in LRA Table 4.3-6 are summarized in the following Tables 1 and 2.

A review of plant specific operating chemistry data at Columbia showed that the average reactor water operating NCW and HWC dissolved oxygen concentrations in the reactor pressure vessel shell and upper head regions and recirculation piping were 87 ppb and 1 ppb, respectively. The Columbia plant-specific low alloy steel FW nozzle locations exposed to these average dissolved oxygen conditions include:

- FW Nozzle to Shell Junctions (i.e., nozzle to shell blend radius) and
- FW Nozzle Forging

The $F_{en}$ calculations for the low alloy steel FW nozzle to shell blend radius location conservatively assumed 150 ppb NWC and 40 ppb HWC dissolved oxygen concentrations. These assumptions are significantly greater than the nominal 87 ppb and 1 ppb operating dissolved oxygen concentrations observed at Columbia station.

The FW nozzle forging limiting location is exposed to reactor vessel water in the gap between the low alloy steel nozzle forging and the nozzle thermal sleeve. Because flow in this region is very low, it was anticipated that there may be periods under HWC conditions when the dissolved oxygen concentration at this location will be higher than 1 ppb. Therefore, the $F_{en}$ calculations for the FW nozzle forging conservatively assumed 150 ppb NWC and 100 ppb HWC dissolve oxygen concentrations.

Similarly a review of plant specific operating chemistry data at Columbia showed that average operating NWC and HWC dissolved oxygen concentrations in the feedwater piping are 58 ppb and 54 ppb, respectively. The Columbia plant-specific nickel alloy FW nozzle location exposed to these average dissolved oxygen conditions includes:

- FW Nozzle Safe End

Consistent with the aforementioned operating data, the FW nozzle nickel alloy safe-end $F_{en}$ calculation assumed that the NWC and HWC dissolved oxygen concentrations were both the default >50 ppb specified in NUREG/CR-5704.

Table 1
Dissolved Oxygen Concentration Inputs for LRA Table 4.3-6

| NUREG/CR-6260 Component | LRA Table 4.3-6 Columbia Plant Specific Location | Material | Normal Water Chemistry DO (ppb) | Hydrogen Water Chemistry DO (ppb) |
|---|---|---|---|---|
| Reactor vessel feedwater nozzle | FW nozzle to shell junction | LAS | 150 | 40 |
| Reactor vessel feedwater nozzle | FW nozzle safe end | Nickel Alloy | >50 | >50 |

Table 2
Dissolved Oxygen Concentration Inputs not included in LRA Table 4.3-6

| NUREG/CR-6260 Component | Additional Columbia Plant Specific Locations not in LRA Table 4.3-6 | Material | Normal Water Chemistry DO (ppb) | Hydrogen Water Chemistry DO (ppb) |
|---|---|---|---|---|
| Reactor vessel feedwater nozzle | FW nozzle forging | LAS | 150 | 100 |

## RAI 3.1.2.1-X1

### Background

Columbia LRA Table 3.1.1, item 3.1.1-55 addresses cast austenitic stainless steel (CASS) Class 1 pump casings and valve bodies and bonnets exposed to reactor coolant > 250°C, which are subject to loss of fracture toughness due to thermal aging embrittlement. The LRA item also indicates that the applicant uses the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program to manage the aging effect for the CASS Class 1 components. The LRA item further states that reduction of fracture toughness for CASS valve bodies less than 4 inches is included in this item and managed by the Small Bore Class 1 Piping Inspection Program. In LRA Table 3.1.2-3, the AMR line item with Row Number 134 also indicates that reduction of fracture toughness in CASS "Valve Bodies < 4 inches" exposed to reactor coolant is managed by the Small Bore Class 1 Piping Inspection Program.

**Issue**

In comparison with the applicant's use of the Small Bore Class 1 Piping Inspection Program, the GALL Report, under item IV.C1-3, recommends the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program to manage loss of fracture toughness due to thermal aging embrittlement for CASS Class 1 pump casings and valve bodies and bonnets exposed to reactor coolant (>250°C). Therefore, the staff found the need to further clarify whether the applicant's aging management approach is consistent with the GALL Report as claimed in LRA Table 3.1.1, item 3.1.1-55.

The staff also noted that the 2001 edition of the ASME Code Section XI with 2002 and 2003 addenda, referenced by GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD," requires that valve body welds in valves less than normal pipe size (NPS) 4 should be examined using surface examination in accordance with Table IWB-2500-1 (Examination Category B-M-1, Item No. B12.30). The staff finds that the ASME Code Section XI requirement is applicable to the applicant's line item Row No. 134 in LRA Table 3.1.2-3 because the valve bodies are less than 4 inches.

Therefore, the staff found the need to clarify whether the CASS valves are less than 4 inches, under the line item with Row No. 134 in Table 3.1.2-3, includes a weld (including weld repair) in the valve bodies and, if a weld is included in the valve bodies, to clarify whether periodic inspections are performed for the valve body weld in a consistent manner with the ASME Section XI Table IWB-2500-1 requirements and the recommendation of the GALL Report. The staff also found the need to further clarify why the applicant's aging management for the CASS valves less than 4 inches is adequate to manage reduction in fracture toughness.

**Request**

1. Clarify whether the CASS Class 1 valves less than 4 inches, under LRA Table 3.1.2-3 line item Row No. 134, have a valve body weld including weld repair and clarify, if the CASS valves have a valve body weld, whether periodic inspections are performed on the valves in accordance with the ASME Code Section XI requirements.

2. Taking into consideration the requirement for the surface examination of the valve body weld described in ASME Code Section XI Table IWB-2500-1, clarify the justification why the Small Bore Class 1 Piping Inspection Program, which uses a one-time inspection rather than periodic inspections and is different from the ASME Section XI Inservice Inspection Program recommended in the GALL Report, is adequate to manage reduction of fracture toughness for the CASS Class 1 valves less than 4 inches.

**Energy Northwest Response**

1. Columbia has no small bore CASS Class 1 valves with either a manufacturing weld or a repair weld in the valve body. All small bore CASS Class 1 valve bodies (and bonnets) at Columbia are cast as one piece. The bodies and bonnets are bolted together. Consequently, there is no surface inspection of these valves in the Columbia ISI program.

2. In Amendment 7, Energy Northwest revised the Small Bore Class 1 Piping Inspection from a one-time inspection to a periodic program, the Small Bore Class 1 Piping Program. The Small Bore Class 1 Piping Program will perform visual and volumetric examinations of small bore valves selected based on their susceptibility to aging, regardless of whether or not the valve bodies have welds. This periodic program will consequently manage reduction of fracture toughness for small bore Class 1 valves better than the ISI program because the Small Bore Class 1 Piping Program will inspect the valves most susceptible to reduction of fracture toughness.

   Amendment 7 was submitted to the NRC in letter GO2-10-135, SK Gambhir (EN) to NRC, dated September 13, 2010. The issue was discussed in the response to RAI B.2.49-1 in that letter.

**RAI 3.1.2.1-X2**

**Background**

Columbia LRA Table 3.1.1, item 3.1.1-48 addresses steel and stainless steel Class 1 piping, fittings and branch connections less than NPS 4 exposed to reactor coolant, which are subject to cracking due to stress corrosion cracking, intergranular stress corrosion cracking and thermal and mechanical loading. The LRA item also indicates that the applicant uses the BWR Water Chemistry Program and Small Bore Class 1 Piping Inspection Program to manage the aging effect. In LRA Table 3.1.2-3, AMR line items with Row Numbers 130 and 131 also indicate that the BWR Water Chemistry Program and Small Bore Class 1 Piping Inspection Program are used to manage cracking due to stress corrosion cracking and intergranular attack for cast CASS valve bodies less than 4 inches exposed to reactor coolant.

**Issue**

In comparison with the applicant's use of the BWR Water Chemistry Program and Small Bore Class 1 Piping Inspection Program, the GALL Report, under item IV.C1-1, recommends the ASME Section XI Inservice Inspection. Subsections IWB, IWC and IWD Program, Water Chemistry Program and One-Time Inspection of ASME Code Class 1 Small-bore Piping Program to manage the cracking due to stress corrosion cracking, intergranular stress corrosion cracking and thermal and mechanical loading. Therefore, the staff found the need to further clarify whether the applicant's aging management approach, which does not use the ASME Section XI Inservice Inspection, Subsections IWB. IWC and IWD Program, is consistent with the GALL Report as claimed in LRA Table 3.1.1, item 3.1.1-48.

The 2001 edition of the ASME Code Section XI with 2002 and 2003 addenda, referenced by GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD," requires that valve body welds in valve bodies less than NPS 4 should be examined using surface examination in accordance with Table IWB-2500-1 (Examination Category B-M-1, Item No. B12.30). The staff finds that this ASME Code Section XI requirement is applicable to the applicant's line items with Row Numbers 130 and 131 in LRA Table 3.1.2-3 because the valve bodies are less than 4 inches.

Therefore, the staff found the need to clarify whether the applicant's aging management for the CASS valves less than 4 inches includes a weld in the valve bodies including weld repair and, if a weld is included in the valve bodies, to clarify whether surface examinations are performed for the valve body weld in a consistent manner with the ASME Section XI Table IWB-2500-1 requirements and the recommendation of the GALL Report. The staff also finds the need to further clarify why the applicant's aging management for the CASS valves less than 4 inches is adequate to manage the cracking due to stress corrosion cracking, intergranular stress corrosion cracking and thermal and mechanical loading.

**Request**

1. Clarify whether the CASS valves less than 4 inches, under LRA Table 3.1.2-3 line items with Row Numbers 130 and 131 and LRA Table 3.1.1 item 3.1.1-48, have a valve body weld including weld repair and clarify, if the CASS valves have a valve body weld, whether periodic inspections are performed on the valves in accordance with the ASME Code Section XI requirements.

2. Taking into consideration the surface examination requirement for the valve body weld described in ASME Code Section XI Table IWB-2500-1, clarify the justification why the Small Bore Class 1 Piping Inspection Program, which is based on a one-time inspection rather than periodic inspections and is different from the ASME Section XI Inservice Inspection Program recommended in the GALL Report, is adequate to manage the cracking due to stress corrosion cracking, intergranular stress corrosion cracking and thermal and mechanical loading.

**Energy Northwest Response**

1. Columbia has no small bore CASS Class 1 valves with either a manufacturing weld or a repair weld in the valve body. All small bore CASS Class 1 valve bodies (and bonnets) at Columbia are cast as one piece. The bodies and bonnets are bolted together. Consequently there is no surface inspection of these valves in the Columbia ISI program. (The valves in LRA Table 3.1.2-3, line items 130 and 131

are the same valves as in LRA Table 3.1.2-3 line item 134 discussed in RAI 3.1.2.1-X1.)

2. As discussed above in the response to RAI 3.1.2.1-X1, Energy Northwest revised the Small Bore Class 1 Piping Inspection from a one-time inspection to a periodic program, the Small Bore Class 1 Piping Program. The Small Bore Class 1 Piping Program will perform visual and volumetric examinations of small bore valves selected based on their susceptibility to aging, regardless of whether or not the valve bodies have welds. This periodic program will consequently manage stress corrosion cracking (SCC) for small bore valves better than the ISI program because it will inspect the valves most susceptible to SCC.

**RAI 3.1.2.3-02**

**Background**

In LRA Table 3.1.2-3, AMR line item with Row Number 129 indicates that CASS valve bodies less than 4 inches exposed to reactor coolant is subject to an aging effect of "Cracking - Flaw Growth" and the aging effect is managed by the Small Bore Class 1 Piping Inspection Program. The LRA line item cites generic note H indicating that the aging effect is not addressed in the GALL Report for this component, material and environment combination.

**Issue**

The staff noted that the aging effect, "Cracking - Flaw Growth," suggests the possibility that a flaw already exists in the CASS valve bodies. However, LRA Section B.2.49 indicates that the Small Bore Class 1 Piping Inspection Program use a one-time inspection approach rather than periodic inspections. Therefore, the staff found the need to clarify whether the components have an existing flaw. And, if a pre-existing flaw exists the staff would like the applicant to clarify why the Small Bore Class 1 Piping Inspection Program, which is based on a one-time inspection rather than periodic inspections, is adequate to manage "Cracking -Flaw Growth."

**Request**

1. Clarify whether the components have an existing flaw.

2. If a flaw exists in the components, clarify what aging mechanism(s) caused the flaw and clarify why the Small Bore Class 1 Piping Inspection Program, which is based on a onetime inspection rather than periodic inspections, is adequate to manage "Cracking Flaw Growth" for the components.

**Energy Northwest Response**

1. Columbia has no small bore Class 1 CASS valves with a flaw. Energy Northwest assumes that indications below the minimum detectable flaw size may exist in components, and thus these indications are not identified or documented. Some Class 1 components have indications that are small enough to be acceptable per the ASME Code; these indications are not documented as flaws.

2. The assumed flaws in the components may be service induced or may be the result of manufacturing. The primary mechanism that would cause growth (or initiation) of these assumed flaws is thermal and mechanical loading. As discussed above in the response to RAI 3.1.2.1-X1, Energy Northwest revised the Small Bore Class 1 Piping Inspection from a one-time inspection to a periodic program, the Small Bore Class 1 Piping Program. The Small Bore Class 1 Piping Program will perform periodic visual and volumetric examinations of small bore components selected based on their susceptibility to aging. This periodic program will consequently manage cracking due to flaw growth better than the ISI program because it will periodically inspect the components most susceptible to the aging effect.

**RAI 3.3.2.3.1-01**

**Background**

Several GALL Report line items (e.g. III.A6-6, III.A6-7, and III.A6-8) discuss aging effects of concrete in a water-flowing environment and suggest AMPs to manage the effects.

**Issue**

LRA Table 3.3.2-1 states that there are no AERMs for concrete piping of the Circulating Water System that is exposed to a raw water (internal) environment and that an AMP is not required. The staff is unclear why an AMP is not credited for management of aging of concrete piping components associated with this line item since they are subjected to a water-flowing environment. Several aging effects exist for concrete exposed to a flowing water environment, as discussed in the GALL Report line items cited above.

**Request**

Explain how aging of these components will be managed, or justify why an AMP is not required for the concrete piping exposed to a raw water (internal) environment.

**Energy Northwest Response**

The relevant conditions do not exist in the raw water environment of the Circulating Water (CW) system for the applicable aging effects to occur. The applicable aging effects for concrete components exposed to raw water, as identified by the Electric Power Research Institute (EPRI) Report 1015078, and the required evaluations of those effects are as follows:

- Change in Material Properties due to Aggressive Chemicals – Change in material properties due to aggressive chemicals is an applicable aging mechanism for concrete components exposed to raw water if there is continued or frequent cyclic exposure to acidic solutions with pH < 5.5, chloride solutions > 500 ppm, or sulfate solutions > 1500 ppm. A dense concrete with low permeability may provide an acceptable degree of protection against mild acid attack. The water of the CW system is not an aggressive environment. Water samples collected from the system do not exceed the above threshold limits for pH, chlorides, and sulfate. The concrete for the subject CW system concrete piping was cast-in-place. Columbia cast-in-place concrete is designed in accordance with ACI 318 and constructed in accordance with ACI 301-72 using materials conforming to ACI and ASTM standards. Concrete constructed to these criteria has low permeability and is effectively protected against sulfate and chloride attack. Therefore, change in material properties due to aggressive chemicals is not an aging effect requiring management for the concrete components in the CW system that are exposed to the "raw water" environment.

- Change in Material Properties due to Leaching of Calcium Hydroxide ($CaOH_2$) – Change in material properties due to leaching of $CaOH_2$ is an applicable aging mechanism for concrete components exposed to raw water if they are exposed to flowing liquid, ponding, or hydraulic pressure and defects in the concrete such as cracks, voids, or low strength are necessary to permit movement of water through the concrete. The concrete for the subject CW system concrete piping was cast-in-place. Columbia cast-in-place concrete is designed in accordance with ACI 318 and constructed in accordance with ACI 301-72 using materials conforming to ACI and ASTM standards. Concrete constructed to these criteria has low permeability (i.e., dense concrete with suitable cement content and well cured). Therefore, change of material properties due to leaching of $CaOH_2$ is not an aging effect requiring management for the concrete components in the CW system that are exposed to the "raw water" environment.

- Cracking due to Reaction with Aggregates – Cracking due to reaction with aggregates is an applicable aging mechanism for concrete components exposed to raw water if improper or contaminated admixtures (salt-contaminated aggregates, seawater, or deicing salt) are used. The concrete for the subject CW system concrete piping was cast-in-place. Columbia cast-in-place concrete specifications require that concrete aggregates conform to ASTM C33 and that the potential reactivity of aggregates be acceptable based on testing in accordance with ASTM Standard Test Method for Potential Alkali Reactivity of Cement-Aggregate Combinations (Mortar-Bar Method) (ASTM C227) or Standard Test Method for Potential Alkali-Silica Reactivity of Aggregates (Chemical Method) (ASTM C289). Therefore, cracking due to reaction with aggregates is not an aging effect requiring management for the concrete components in the CW system that are exposed to the "raw water" environment.

- Loss of Material due to Abrasion or Cavitation – Loss of material due to abrasion or cavitation is an applicable aging effect for concrete components exposed to raw water if it is continuously exposed to flowing water containing abrasives and open channel water velocities greater than 40 fps, or closed conduit water velocities greater than 25 fps. The water of the CW system is filtered of most abrasives. The flow velocity is determined by the number of operating pumps and cooling towers. Even during pump/tower combinations that are only allowed for short durations the flow velocity is less than 9 fps. Therefore, loss of material due to abrasion or cavitation is not an aging effect requiring management for the concrete components in the CW system that are exposed to the "raw water" environment.

- Loss of Material due to Aggressive Chemicals – Loss of material due to aggressive chemicals is an applicable aging mechanism for concrete components exposed to raw water if there is continued or frequent cyclic exposure to acidic solutions with pH < 5.5, chloride solutions > 500 ppm, or sulfate solutions > 1500 ppm; a dense concrete with low permeability may provide an acceptable degree of protection against mild acid attack. The water of the CW system is not an aggressive environment. Water samples collected from the system do not exceed the above threshold limits for pH, chlorides, and sulfate. The concrete for the subject CW system concrete piping was cast-in-place. Columbia cast-in-place concrete is designed in accordance with ACI 318 and constructed in accordance with ACI 301-72 using materials conforming to ACI and ASTM standards. Concrete constructed to these criteria has low permeability and is effectively protected against sulfate and chloride attack. Therefore, loss of material due to aggressive chemicals is not an aging effect requiring management for the concrete components in the CW system that are exposed to the "raw water" environment.

- Loss of Material due to Corrosion of Embedded Steel and Steel Reinforcement – Loss of material due to corrosion of embedded steel and steel reinforcement is an applicable aging mechanism for concrete components exposed to raw water if the concrete is not of good quality, well consolidated, and properly cured or the embedded steel is exposed to an aggressive environment such as aggressive groundwater or sea water (concrete pH < 11.5, chlorides > 500 ppm, and sulfates > 1500 ppm). The water of the CW system is not an aggressive environment. The concrete for the subject CW system concrete piping was cast-in-place. Columbia cast-in-place concrete is designed in accordance with ACI 318 and constructed in accordance with ACI 301-72 using materials conforming to ACI and ASTM standards. Concrete constructed to these criteria is of good quality, well consolidated, and properly cured. Therefore, loss of material due to corrosion of embedded steel and steel reinforcement is not an aging effect requiring management for the concrete components in the CW system that are exposed to the "raw water" environment.

- Cracking and Loss of Material due to Freeze-Thaw – Freeze-thaw is an applicable aging mechanism for concrete exposed to raw water for plants located in areas in which weathering conditions are moderate or severe; however, freeze-thaw is not a significant concern for concrete mix design that meets the air content and water-to-cement ratio specified in ACI 318-63. Columbia cast-in-place concrete is designed in accordance with ACI 318 ensuring that it is good quality, well consolidated, and properly cured. Also, the subject concrete pipe is below-grade; and the raw water environment to which it is normally exposed is returning from the Service Water system loads and is therefore relatively warm. Therefore, cracking and loss of material due to freeze-thaw are not aging effects requiring management for the concrete components in the CW system that are exposed to the "raw water" environment.

Therefore, as stated in the Table 3.3.2-1 of the LRA, there are no aging effects requiring management or aging management programs credited for managing concrete piping exposed to a raw water environment in the CW system.

**RAI 3.3.2.3.1-02**

**Background**

Several GALL Report line items (e.g. III.A6-2, III.A6-3, and III.A6-4) discuss aging effects of concrete in a soil environment and provide AMPs to manage the effects.

**Issue**

LRA Table 3.3.2-1 states that there are no AERMs for concrete piping of the Circulating Water System that is exposed to a soil (external) environment and an AMP is not required. The staff is unclear why an AMP is not credited for management of aging of concrete piping components associated with this line item since they are subjected to a soil (external) environment. Several aging effects exist for concrete exposed to a soil environment, as discussed in the GALL Report line items cited above.

**Request**

Explain how aging of these components will be managed, or justify why an AMP is not required for the concrete piping exposed to a soil (external) environment.

**Energy Northwest Response**

The relevant conditions do not exist in the soil (external) environment of the subject CW system piping for the applicable aging effects to occur. The applicable aging effects for concrete components exposed to a soil (external) or below grade environment, as identified by the EPRI Report 1015078, and the required evaluations of those effects are as follows:

- Change in Material Properties due to Aggressive Chemicals – Change in material properties due to aggressive chemicals is an applicable aging mechanism for external surfaces of concrete components if there is continued or frequent cyclic exposure to acidic solutions with pH < 5.5, chloride solutions > 500 ppm, or sulfate solutions > 1500 ppm; a dense concrete with low permeability may provide an acceptable degree of protection against mild acid attack. The groundwater at Columbia is not an aggressive environment. Groundwater samples collected at the site do not exceed the above threshold limits for pH, chlorides, and sulfates. The concrete for the subject CW concrete piping was cast-in-place. Columbia cast-in-place concrete is designed in accordance with ACI 318 and constructed in accordance with ACI 301-72 using materials conforming to ACI and ASTM standards. Concrete constructed to these criteria has low permeability and is effectively protected against sulfate and chloride attack. Therefore, change of material due to aggressive chemicals is not an aging effect requiring management for the external surfaces of these concrete components in the CW system that are exposed to the soil (external) environment.

- Change in Material Properties due to Leaching of $CaOH_2$ – Change in material properties due to leaching of $CaOH_2$ is an applicable aging mechanism for external surfaces of concrete components if they are exposed to flowing liquid, ponding, or hydraulic pressure and defects in the concrete such as cracks, voids, or low strength are necessary to permit movement of water through the concrete. The concrete for the subject CW concrete piping was cast-in-place. Columbia cast-in-place concrete is designed in accordance with ACI 318 and constructed in accordance with ACI 301-72 using materials conforming to ACI and ASTM standards. Concrete constructed to these criteria has low permeability (i.e., dense concrete with suitable cement content and well cured). Therefore, change of material properties due to leaching of $CaOH_2$ is not an aging effect requiring management for the external surfaces of concrete components in the CW system that are exposed to the soil (external) environment.

- Cracking due to Reaction with Aggregates – Cracking due to reaction with aggregates is an applicable aging mechanism for external surfaces of concrete components if improper or contaminated admixtures (salt-contaminated aggregates, seawater, or deicing salt) are used. The concrete for the subject CW concrete piping was cast-in-place. Columbia cast-in-place concrete specifications require that concrete aggregates conform to ASTM C33 and that the potential reactivity of aggregates be acceptable based on testing in accordance with ASTM Standard Test Method for Potential Alkali Reactivity of Cement-Aggregate Combinations (Mortar-Bar Method) (ASTM C227) or Standard Test Method for Potential Alkali-Silica Reactivity of Aggregates (Chemical Method) (ASTM C289). Therefore, cracking due to reaction with aggregates is not an aging effect requiring management for the external surfaces of concrete components in the CW system that are exposed to the soil (external) environment.

- Cracking due to Settlement – Cracking due to settlement is an applicable aging mechanism for external surfaces of concrete components if founded on soft soil and/or there are significant changes in underground water conditions over a long period of time (i.e., lowering of the ground water table). Foundations for all Columbia plant structures are supported in structural backfill. The backfill provides safe bearing for the structural foundations and settlements are estimated to be minimal. In order to compare the calculated (estimated) to actual settlement, measurement points were established at the corners of the substructure of the reactor building, radwaste and control building, spray ponds, and along the four sides of the sub-structure of the turbine generator building. These points have been monitored systematically since the beginning of construction. The settlement observation records to date for these facilities are included in Columbia's FSAR and the results of settlement monitoring show that the actual maximum differential settlements are well within the estimated differential settlements and that they remain of no consequence to the design of plant structures or appurtenances. Also, the measured settlement rate in the time frame from 1986 to 1991 has virtually leveled off (i.e. zero settlement) and was less than an average of 0.001 feet/year for both spray ponds. Columbia does not employ a de-watering system in any of the site structures for control of settlement since the groundwater level at the site is sufficiently lower than the deepest foundation in the complex as discussed in LRA section 2.4.2 and 2.4.3. Therefore, cracking due to settlement is not an aging effect requiring management for the external surfaces of concrete components in the CW system that are exposed to the soil (external) environment because the total differential settlement experienced in the past 20 years for Columbia's structures is well within the permissible limits and no settlement has manifested itself via cracked walls or cracked foundations in any structure.

- Loss of Material due to Aggressive Chemicals – Loss of material due to aggressive chemicals is an applicable aging mechanism for external surfaces of concrete components if there is continued or frequent cyclic exposure to acidic solutions with pH < 5.5, chloride solutions > 500 ppm, or sulfate solutions > 1500 ppm; a dense concrete with low permeability may provide an acceptable degree of protection against mild acid attack. The groundwater at Columbia is not an aggressive environment. Groundwater samples collected at the site do not exceed the above threshold limits for pH, chlorides, and sulfates. The concrete for the subject CW concrete piping was cast-in-place. Columbia cast-in-place concrete is designed in accordance with ACI 318 and constructed in accordance with ACI 301-72 using materials conforming to ACI and ASTM standards. Concrete constructed to these criteria has low permeability and is effectively protected against sulfate and chloride attack. Therefore, loss of material due to aggressive chemicals is not an aging effect requiring management for the external surfaces of concrete components in the CW system that are exposed to the soil (external) environment.

- <u>Loss of Material due to Corrosion of Embedded Steel and Steel Reinforcement</u> – Loss of material due to corrosion of embedded steel and steel reinforcement is an applicable aging mechanism for external surfaces of concrete components if the concrete is not of good quality, well consolidated, and properly cured or the embedded steel is exposed to an aggressive environment such as aggressive groundwater or sea water (concrete pH < 11.5, chlorides > 500 ppm, and sulfates > 1500 ppm). The groundwater at Columbia is not an aggressive environment. Groundwater samples collected at the site do not exceed the above threshold limits for pH, chlorides, and sulfates. The concrete for the subject CW concrete piping was cast-in-place. Columbia cast-in-place concrete is designed in accordance with ACI 318 and constructed in accordance with ACI 301-72 using materials conforming to ACI and ASTM standards. Concrete constructed to these criteria is of good quality, well consolidated, and properly cured. Therefore, loss of material due to corrosion of embedded steel and steel reinforcement is not an aging effect requiring management for the external surfaces of concrete components in the CW system that are exposed to the soil (external) environment.

Therefore, as stated in the Table 3.3.2-1 of the License Renewal Application, there are no aging effects requiring management or aging management programs credited for managing concrete piping exposed to a soil (external) environment in the CW system.

## <u>RAI 3.5.2.2.2-01</u>

### <u>Background</u>

Industry standards identified in the GALL Report Structures Monitoring AMP suggest a five year inspection interval for structures exposed to a natural environment, structures inside primary containment, continuous fluid-exposed structures, and structures retaining fluid or pressure, and a ten year inspection interval for below-grade structures and structures in a controlled interior environment.

### <u>Issue</u>

LRA Section 3.5.2.2.2.1 states that the Structures Monitoring Program is credited for aging management of affected concrete structures and structural components even if the AMR did not identify aging effects requiring management; however, the LRA does not discuss the inspection interval under the Structures Monitoring Program.

**Request**

Explain in more detail the inspection interval for the structures in the scope of license renewal. If the inspection interval exceeds the recommendations in the GALL Report, explain the basis for extending the interval; include relevant operating experience in the discussion.

**Energy Northwest Response**

The Structures Monitoring Program (SMP) inspection frequency is consistent with industry standards and is conservatively performed at a two-cycle (refueling) basis every 4 years and will continue throughout the period of extended operation. Structures exposed to a natural environment, structures inside primary containment, continuous fluid-exposed structures, structures retaining fluid or pressure, below-grade structure interiors, and structures in a controlled interior environment fall in the two-cycle inspection frequency. The two-cycle inspection frequency is an administrative frequency set for the SMP. The committed inspection frequency is consistent with NUREG-1801 Structures Monitoring Program of a five year inspection interval as suggested in Chapter 6 of ACI 349.3R-96.

Structures in the scope of license renewal which are currently not within scope of Maintenance Rule (10 CFR 50.65) will be added to the SMP. A complete list of structures in-scope of the SMP will be provided as indicated in LRA Table A-1 item 50. All structures in-scope of the SMP will be subjected to the inspection frequency stated above.

Opportunistic inspection will be employed for inaccessible below-grade concrete areas. As stated in LRA Table item 3.5.1-31, the SMP is committed to review of site ground water and raw water pH, chlorides, and sulfates in order to validate that the below-grade environment remains non-aggressive during the period of extended operation and will include examination of exposed concrete for age-related degradation when a below-grade concrete component becomes accessible through excavation. Opportunistic inspection for inaccessible below-grade concrete areas is consistent with NUREG-1801 for sites with non-aggressive below-grade environment.

The SMP incorporates provisions for increased monitoring described in NRC Regulatory Guide 1.160. This includes clarifications for monitoring under Paragraph (a)(1) of 10 CFR 50.65, including additional degradation-specific condition monitoring and increased frequency of assessments until ongoing corrective actions are complete and functional performance is assured.

Structures that are free of deficiencies or degradation that could prevent any system in the structure from performing its safety-related function meet the performance criteria for structures performance classification of 10 CFR 50.65 (a)(2) or "(a)(2)". Structures that are unable to perform their intended functions, or are capable of performing their intended functions but have deficiencies which could deteriorate to an unacceptable condition if not analyzed or corrected prior to the next scheduled examination fall under performance classification 10 CFR 50.65 (a)(1) or "(a)(1)". Structures initially categorized as performance classification "(a)(1)" may be re-categorized as "(a)(2)" where the root cause has been determined and effective corrective actions have been implemented.

Periodic assessment is conducted to address the requirement of 10 CFR 50.65 (a)(3) by completing a periodic assessment of maintenance effectiveness, as measured by the Maintenance Rule program, at least once every 24 months. The periodic assessment is a summary document that relies on ongoing activities in the Maintenance Rule Program for input. The maintenance rule database contains the results of the screening of all condition reports and various operation logs in the Maintenance Preventable Functional Failure (MPFF) table. These items are screened for potential functional failures of in-scope structures, systems, and components (SSCs) which are then further evaluated by a system engineer. Results are analyzed for trends and are summarized in periodic assessment reports.

## RAI 3.5.2.3.13-01

### Background

In GALL Report AMP XI.S6, "Structures Monitoring Program," program elements 3 and 4 state that for each structure/aging effect combination the specific parameters monitored or inspected are selected to ensure that the aging degradation leading to loss of intended function will be detected and quantified before there is a loss of intended function.

### Issue

Table 3.5.2-13 states that calcium silicate and fiberglass insulation materials exposed to air-outdoor or air-indoor environments have no AERMs and an AMP is not required. The LRA also states that the components have an intended function of providing structural or functional support to non-safety related equipment whose failure could prevent satisfactory accomplishment of required safety functions. The staff is unclear why an AMP is not credited for managing aging of these.

### Request

Explain how aging of these components will be managed, or justify why an AMP is not required for the calcium silicate and fiberglass insulation materials exposed to air-outdoor or air-indoor environments.

**Energy Northwest Response**

Aging management reviews have determined that no aging management is required for calcium silicate and fiberglass insulation materials exposed to air-outdoor or air-indoor environments as indicated in LRA Table 3.5.2-13. The information used to determine the aging effects and associated aging mechanisms for insulation materials was gathered from various industry sources and is discussed in EPRI Report 1015078, "Structural Tools." Plant specific and industry operating experience review on calcium silicate and fiberglass insulation has not identified any age-related degradation.

The design specification for thermal insulation at Columbia specifies that insulation have uniform composition and be capable of withstanding the temperatures and environmental conditions to which they are subjected without deterioration evidenced by shrinkage, calcination, change of form, settling, or pulverization. Only incombustible insulation materials are utilized. All insulation materials and accessories are manufactured, processed, packaged, shipped, stored, and installed in a manner that will limit, to the maximum extent practical, chloride and fluoride contamination from external sources.

Insulation applied to piping and equipment is molded, shaped, or block-type inhibited calcium silicate type insulation. The insulation is composed of hydrous calcium silicate conforming to ASTM C533 and is manufactured with reinforcing mineral fiber. Where anti-sweat insulation for piping and its appurtenances is specified, fiberglass insulation conforming to ASTM C547 is used. Fiberglass insulation conforming to ASTM C547 can also be an alternative to calcium silicate for instrumentation piping and tubing.

All runs of insulated piping are covered with aluminum jacketing material. The aluminum jacketing material has a vapor proof barrier either bonded to the inside of the aluminum or over the outside of the insulation to protect the aluminum from chemical action with the insulation. Removable insulation sections are used for piping and equipment that required periodic inspection or maintenance. Removable thermal insulation with jacketing or removable pad-type insulation is applied in such a manner that it can be readily removed and reinstalled without damage to insulation or jacketing. Where cold weather insulation is specified for outdoor piping, a weather-proof molded inhibited calcium silicate insulation of the required thickness is applied. Weather-proofing includes aluminum jacketing applied over the insulation with all joints lapped and positioned to properly shed water or mastic reinforced with open mesh glass fabric applied over the insulation.

Aging management review evaluation for insulation material was taken from the EPRI Report 1015078, "Structural Tools." The insulating materials for non-reflective insulation are fabricated of asbestos, calcium silicate, glass fiber, or ceramic fiber. The thermal resistance (insulating) characteristics of mass insulation systems are not expected to naturally degrade over the course of their service life as proper selection, design and installation for the specific service and condition is assumed. Unless protective coverings of mass insulation systems are damaged, loss/degradation of insulating material is not a concern. Mass insulation systems used in nuclear plant applications typically are sealed and include a combination of insulating material and a weather barrier, vapor barrier, condensate barrier, or covering for the specific service. This outer covering (or barrier) protects mass insulation from the weather, solar/UV radiation, or atmospheric contaminants, and mechanical damage, but permits the evaporation of any moisture vapor. Typically, atmospheric pollutants and contaminants, both indoors and outdoors, are insufficient to concentrate and thereby attack properly designed, selected and installed weather/vapor barriers or covering of mass insulation systems. Also, the coverings protect the insulating materials from exposure to corrosive elements that could change their material properties. Therefore, degradation of insulating materials is not an aging effect that requires management.

Industry failure data and NRC generic communications were reviewed to determine if there are any additional aging effects that should be considered for insulation. This review included searches of INPO databases, NRC IE Information Bulletins, and NRC LERs. The search was performed for insulating material. Review of NRC generic communications and INPO databases did not identify insulating material aging related issues. Industry experiences on insulating material were related to insulating material as foreign objects being dislodged causing sump debris blockage which is event driven.

<u>Air-indoor Environment:</u>
The insulation (calcium silicate and fiberglass) and insulation jacketing materials (aluminum, stainless steel) do not require an aging management program as shown in LRA Table 3.5.2-13 because these insulation materials are exposed to indoor air environment. In this environment, these materials have no aging effects requiring management. The operating experience review specifically considered plant-specific information related to the effects of aging on insulation materials. The review confirmed that no aging effects requiring management are applicable to these insulation materials that are subject to the AMR.

<u>Air-outdoor Environment:</u>
The insulation and insulation jacketing materials do not require an aging management program as shown in LRA Table 3.5.2-13. The operating experience review specifically considered plant-specific information related to the effects of aging on insulation materials and confirmed that no aging effects requiring management are applicable to the insulation materials. The outer covering (or barrier) protects mass insulation from the weather, solar/UV radiation or atmospheric contaminants. LRA Plant Specific Note 0525 addresses aging management of insulation outer covering used in an air-outdoor application. The aging effect of loss of material was determined not applicable since Columbia is located in an in-land rural environment and is not exposed to aggressive environmental conditions. Component external surfaces are not continuously wetted or exposed to an aggressive ambient environment (such as a saltwater atmosphere, sulfur dioxide, etc.) or industrial locations. However, the Structures Monitoring Program is committed to confirm the absence of significant aging effects on outdoor insulation for the period of extended operation.

# License Renewal Application
# Amendment 13

| Section No. | Page No. | RAI No. |
|---|---|---|
| Table 4.3-2<br>New row | 4.3-4a | RAI B.2.24-04 |
| Table 4.3-6<br>footnote (2) | 4.3-16 | RAI 4.3-05 |
| Table C-8<br>Item (4) | C-21 | RAI 4.3-02 |

Columbia is analyzed for 120 startups and shutdowns. The 120 startups consist of 117 normal startups and 3 natural circulation startups. The 120 shutdowns consist of 111 normal shutdowns, 8 single safety or relief valve blowdowns, and 1 rapid depressurization with delayed trip.

**Table 4.3-2**
**Actual Cycles and Projected Cycles**

| Conditions | Analyzed cycles | Actual cycles 12/13/1984 through 2/16/2010 | 60 year (12/13/2044) projection(1) | Cycles for future analyses |
|---|---|---|---|---|
| Boltup/Unbolt | 123 | 23 | 54 | 60 |
| Reactor Startup (100 degF/hr) | 120 | 94 | 224 | 250 |
| Reactor Shutdown (100 degF/hr) | 111 | 93 | 221 | 250 |
| Vessel Pressure Tests | 130 | 23 | 54 | 65 |
| Loss of Feedwater Heaters | 80 | 0 | 0 | 80 |
| Scram – Loss of feedwater pumps, isolation valves closed | 10 | 7 | 16 | 20 |
| Scram – Single safety relief valve blowdown | 8 | 1 | 2 | 8 |
| Scram – TG trip, FW on, isolation valves open | 40 | 23 | 54 | 60 |
| Scram – HPCS Injection | 30 | 12 | 28 | 60(2) |
| Scram – Other | 140 | 39 | 92 | 90 |
| LPCS operation | 10 | 0 | 0 | 10 |
| HPCS operation | 10 | 3 | 7 | 10(2) |
| LPCI operation | 10 | 0 | 0 | 10 |
| SLC operation | 10 | 0 | 0 | 10 |

(1) Projections were not changed for those events that have not occurred.
(2) Total HPCS injection cycles from scrams (60) and non-scrams (10) should not exceed 70.

Add the following line:

| | | | | |
|---|---|---|---|---|
| Operating Basis Earthquake (OBE) | 10/50 | 0 | 0 | 10/50 |

**Table 4.3-6 (continued)**
**CUFs for NUREG/CR-6260 Locations**

| NUREG/CR-6260 generic locations | | Columbia plant-specific locations | Material type | Revised CUF in air [(2)] | Per NUREG/CR-5704 and NUREG/CR-6583 | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | Min. $F_{en}$ [(3)] | Average $F_{en}$ [(3)] | Max. $F_{en}$ [(3)] | Environmentally assisted CUF |
| 4 | Core spray line reactor vessel nozzle and associated Class 1 piping | LPCS piping | CS | 0.155 | 1.74 | 5.22 | 7.33 | 0.809 |
| 4 | Core spray line reactor vessel nozzle and associated Class 1 piping | HPCS piping | CS | 0.321 | 1.74 | 2.25 | 2.49 | 0.723 |
| 5 | Residual Heat Removal (RHR) nozzles and associated Class 1 piping | RHR/LPCI nozzle safe end | Nickel Alloy | 0.139 | 2.55 | 6.16 | 6.94 | 0.856 |
| 5 | Residual Heat Removal (RHR) nozzles and associated Class 1 piping | RHR/LPCI nozzle safe end extension | CS | 0.190 | 1.74 | 2.39 | 2.75 | 0.455 |
| 5 | Residual Heat Removal (RHR) nozzles and associated Class 1 piping | RHR/LPCI piping | CS | 0.001 | 20.49 | 20.49 | 20.49 | 0.02 |
| 6 | Feedwater line Class 1 piping | RFW/RWCU Tee [(1)] | CS | 0.210 | 1.74 | 1.85 | 2.85 | 0.389 |

Note: CS is carbon steel, LAS is low alloy steel, SS is stainless steel

(1) Assumed NWC dissolved oxygen concentration equaled to 150 ppb for the RFW nozzle and RFW/RWCU Tee $F_{en}$ calculation.

~~(2) CUF of record previously identified in Table 4.3-3 and Table 4.3-5.~~

(3) Effective $F_{en}$ ~~determined for each~~ load pair based on a time weighted average for HWC and NWC for 60 years of operation. Average $F_{en}$ is the reported ~~environmentally assisted~~ CUF divided by the non-environmentally assisted CUF.

Replace footnote 2 with the following footnote:

(2) The "Revised CUF in air" is the maximum computed CUF (in air) for the wetted surface of interest for the evaluation of the effect of the reactor water environment. The CUF of record was previously identified in Table 4.3-3 and Table 4.3-5.

**Table C-8**

| BWRVIP-47-A<br>BWR Lower Plenum Inspection and Flaw Evaluation Guidelines | |
|---|---|
| **Applicant Action Item Text** | **Plant-Specific Response** |
| (3) 10 CFR 54.22 requires that each LR application include any TS changes (and the justification for the changes) or additions necessary to manage the effects of aging during the period of extended operation as part of the LR application. In its Appendix A to the BWRVIP-47 report, the BWRVIP stated that there are no generic changes or additions to TSs associated with the lower plenum as a result of its AMR and that the applicant will provide the justification for plant-specific changes or additions. Those LR applicants referencing the BWRVIP-47 report for the lower plenum shall ensure that the inspection strategy described in the BWRVIP-47 report does not conflict or result in any changes to their TSs. If technical specification changes do result, then the applicant should ensure that those changes are included in its LR application. | No technical specification changes are required for the inspection strategy described in the BWRVIP-47-A report. |
| (4) Due to fatigue of the subject safety-related components, applicants referencing the BWRVIP-47 report for LR should identify and evaluate the projected CUF as a potential TLAA issue. | The only TLAAs identified for the lower plenum are the cumulative usage factors for the control rod drive (CRD) housings~~, CRD stub tubes, and incore housing penetrations.~~ These are addressed in Section 4.3.1 (Table 4.3-3) of the LRA. |

Insert " and CRD stub tubes."