ENERGY NORTHWEST

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GO2-10-139

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, GO2-10-11, dated January 19, 2010, WS Oxenford (Energy Northwest) to NRC, "License Renewal Application"
2) Letter dated August 16, 2010, NRC to SK Gambhir (Energy Northwest), "Request for Additional Information for the Review of the Columbia Generating Station, License Renewal Application," (ADAMS Accession No. ML 102230369)
3) Letter dated August 16, 2010, NRC to SK Gambhir (Energy Northwest), "Request for Additional Information for the Review of the Columbia Generating Station, License Renewal Application," (ADAMS Accession No. ML 102080506)

Dear Sir or Madam:

By Reference 1, Energy Northwest requested the renewal of the Columbia Generating Station (Columbia) operating license. Via References 2 and 3, the Nuclear Regulatory Commission (NRC) requested additional information related to the Energy Northwest submittal.

Transmitted herewith in the attachments are the Energy Northwest responses to the Requests for Additional Information (RAI) contained in References 2 and 3. No new commitments are included in this response. Amendment 11 to the License Renewal Application (LRA) submitted in Reference 1 is provided in the enclosure to this letter.

A035
NRR

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

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: 1) Response to Request for Additional Information
2) Response to Request for Additional Information

Enclosure: License Renewal Application Amendment 11

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

RAI B.2.28-2

Background:

The Generic Aging Lessons Learned (GALL) Report X1. M17 establishes that for monitoring and trending of piping systems susceptible to flow-accelerated corrosion (FAC), a predictive code should be used to predict component degradation. In license renewal application (LRA) Section B.2.28, the applicant states that an enhancement to the FAC Program includes adding gray cast iron as a material identified as susceptible to FAC. The applicant further states that the guidance and recommendations of Electric Power Research Institute (EPRI) NSAC-202L will be utilized to ensure that the integrity of piping systems susceptible to FAC is maintained. EPRI NSAC-202L, Rev 3, recommends using CHECWORKS as a tool to predict and monitor the wear rate in piping systems susceptible to FAC but it is modeled for carbon and low alloy steel piping.

Issue:

The LRA does not contain information regarding the method that will be used to monitor or inspect the gray cast iron components for FAC.

Request:

Please discuss how monitoring and inspection of gray cast iron susceptible to FAC will be performed to ensure that structural integrity will be maintained.

Energy Northwest Response:

The use of CHECWORKS is not the only tool that NSAC-202L recommends for the sample selection for FAC inspections.

The integrity of the trap bodies is monitored in the same way that the integrity of other piping components (e.g., steel trap bodies and steel valve bodies) in lines susceptible to FAC is monitored. As listed in LRA Tables 3.4.2-1 and 3.4.2-4, gray cast iron components susceptible to FAC are steam trap bodies in Auxiliary Steam (AS) and Main Steam (MS) lines. The AS and MS piping and components are included in the FAC program at Columbia Generating Station (Columbia). The sample selection for inspection of small bore piping and components is directed by plant procedures that were developed based on the guidance provided in NSAC-202L, Revision 2. The sample selection guidance in NSAC-202L, Revision 3, is the same as that provided in Revision 2.

The Columbia systems have been screened for susceptibility to FAC and the lines within susceptible systems have been further screened to establish a population from which to select inspection locations. Variables influencing FAC are considered in the sample selection. Of particular importance are components with high flow velocity and turbulence. As flow and operating conditions for these components and piping are not well defined, engineering judgment by FAC experienced engineers is used to ensure the sample is sufficient. Consideration is also given to including components along with downstream piping that are known within the industry to be particularly susceptible, such as control valves, orifices, or steam traps. Predictive methodology such as CHECWORKS is not a suitable tool for these sample selections. Therefore, the use of engineering judgment is an important tool for the selection of examination locations.

As recommend by NSAC-202L, when examinations detect significant unexpected FAC wear the sample size for that line is expanded. When inspections of the expanded sample detect additional components with significant FAC wear, the sample is further expanded. When inspections of the further-expanded sample detect additional components with significant wear, the sample expansion is repeated until no additional components with significant wear are detected. Piping components that are determined to not meet the wall thickness requirements for continued operation are repaired or replaced. Although piping components (e.g., valve bodies and trap bodies) may not have been specifically included in the initial sample population, the sample expansion may include piping components (e.g., trap bodies), that would be visually inspected per EPRI NSAC-202L guidance, based on the results of the sample expansion inspection.

RAI 3.6-1

Background:

Standard Review Plan (SRP) Table 3.6.1, Item Number 3.6.1-9, credits the GALL Report aging management program (AMP) XI.S6, Structures Monitoring Program to manage the aging effect/mechanism loss of material due to general corrosion for metal-enclosed bus enclosure assemblies.

Issue:

In LRA Table 3.6.2-1, the applicant references Item 3.6.1-9 and generic note A, and credits the Structures Monitoring Program to manage aging for metal-enclosed bus enclosure assemblies. However, the discussion of the Structures Monitoring Program in Appendix B of the LRA does not indicate that the metal-enclosed bus enclosure assemblies are within the scope of the Structures Monitoring Program.

Request:

Confirm that the scope of Structures Monitoring Program includes the metal-enclosed bus enclosure assemblies, and revise the scope of Structure Monitoring Program as appropriate.

Energy Northwest Response:

Metal-enclosed buses were termed Electrical Bus Ducts in the Civil/Structural review and are covered in LRA Table 3.5.2-13 lines 37 to 42. Electrical Bus Duct enclosure assemblies are in-scope and subject to aging management.

As stated in LRA Table 3.6.2-1 Note 0605:

> The inspection of the metal-enclosed bus enclosure assembly elastomers (joints, seals, gaskets) will be performed as part of the Metal-Enclosed Bus Program. The elastomers will be inspected when the covers of the various bus enclosure sections are removed. The Structures Monitoring Program will address the metallic portion of the enclosure assembly and the external structural supports for the various bus assemblies (along with the building penetrations and seals where the bus ducts enter the Reactor Building).

LRA B.2.50 does not specifically list Electrical Bus Duct. However, as stated in LRA B.2.50 under Required Enhancements - Parameters Monitored or Inspected:

> Identify that the term "structural component" for inspection includes component types that credit the Structures Monitoring Program for aging management.

The identification of Electrical Bus Duct as a component type is an action that is required to comply with the commitment to complete this enhancement.

RAI 3.6-2

Background:

In LRA Table 3.6.2-1, under component/commodity group, "Uninsulated Ground Conductors and Connections," the applicant indicated that there are no aging effects requiring management for the metallic components of uninsulated ground conductors and connections.

Issue:

The LRA did not provide technical justification of how uninsulated ground conductors and connections are not subject to aging degradation such as loss of material due to general corrosion in soil environment.

Request:

Provide a detail technical justification as to why uninsulated ground conductors are not subject to any aging degradation.

Energy Northwest Response:

The uninsulated ground conductors and connections at Columbia include the bare conductors which ground various buildings and the grounding grid. The conductors are described in the applicable electrical drawings as bare copper. The connections are not strictly electrical connections, but straps, lugs, or mounting brackets that support the ground conductors. The bare copper rods and conductor connections could potentially be subject to corrosion and a loss of material properties as mentioned in the EPRI Electrical Handbook. However, the review of industry operating experience (from the Electrical Handbook) listed no findings associated with uninsulated ground conductors and connections. With respect to aging management, the Safety Evaluation Report (SER) for the Turkey Point License Renewal Application contained the following determination.

> The ground cable material used at Turkey Point, Units 3 and 4, is copper. Copper is a good choice for this application because of its high electrical conductivity, high fusing temperature, and high corrosion resistance. Copper is also relatively strong, and it is easy to join by welding, compression, or clamping. Ground connections are commonly made with welds or mechanical type connectors, which include compression-, bolted-, and wedge-type devices.
>
> The applicant has reviewed the available industry technical information regarding material aging and has determined that there are no aging effects requiring management for copper grounding materials. In addition, the applicant has reviewed industry and plant operating experience and did not identify any failures of copper ground systems due to aging effects. The applicant also inspected several underground portions of the Turkey Point grounding system during plant modification to add two additional diesel generators in 1990 and 1991, and did not identify any aging-related effects. The system was approximately 20 years old at the time of the inspection. The applicant states that that portion of the grounding system inspected is buried in the same type of soil as other underground portions of the grounding system. Therefore, based on industry and plant-specific operating experience, no aging effects requiring management were identified for the plant grounding system. The staff agrees with the applicant's assessment and conclusion that no AMP is required for the plant ground system.

Likewise, a review of the Columbia plant-specific operating experience showed no failures of the plant grounding system. In addition, the lack of significant rainfall at Columbia and the moderate climate argue against any deleterious impact to the copper conductors from corrosion. Therefore, no aging effects requiring management are identified for the uninsulated ground conductors and connections at Columbia.

RAI 3.6-3

Background:

GALL Report, Vol. 2, Rev. 1, Item VI.A-8, "Fuse Holders (Not Part of a Larger Assembly; Metallic Clamp)," identifies the aging effect and aging mechanism as fatigue, ohmic heating, thermal cycling, electrical transients, frequent manipulation, vibration, chemical contamination, corrosion and oxidation. The associated AMP XI.E5, "Fuse Holders," states that fuse holders within the scope of license renewal should be tested to provide an indication of the condition of the metallic clamps of fuse holders. In Table 3.6.1, under Item 3.6.1-06 of the LRA, the applicant indicates that the aging effects detailed in NUREG-1801 are not applicable for this item.

Issue:

In LRA Appendix B, Table B-1, the applicant stated that Fuse Holder Program is not credited for license renewal. Table 3.6.2-1, under Fuse Holder Metallic Clamp component type, also states that these aging effects are not applicable at Columbia Generating Station. The applicant does not provide a detailed evaluation for each aging effect identified in GALL Report and AMP XI.E5.

Request:

Provide a detailed evaluation that addresses the aging effect/mechanisms identified in GALL Report, Vol. 2, Revision 1, and Item VI.A-8 that supports the conclusions made in LRA Table 3.6.1, Item 3.6.1-06.

Energy Northwest Response:

As discussed in the GALL Report, the scope of the XI.E5 FUSE HOLDERS program states:

> This program applies to fuse holders located outside of active devices and that are considered susceptible to aging effects. Fuse holders inside an active device (e.g., switchgears, power supplies, power inverters, battery chargers, and circuit boards) are not within the scope of this program.

At Columbia, a search was done to identify fuse holders within the scope of License Renewal that are located in enclosures that do not contain active devices. The result of the search was a list of 14 passive enclosures. Four of these enclosures are located in the Radwaste Building within the Control Structure on the 467 foot elevation in the battery rooms. The remaining 10 are located in the Reactor Building within Secondary Containment. The following provides a basis for the conclusion that the fuse holders (metallic clamps) are not subject to the aging effects/mechanisms identified in NUREG-1801 Volume 2 Revision 1, Generic Aging Lessons Learned (GALL) Report Tabulation of Results, Item VI.A-8.

Fatigue

NUREG-1760, "Aging Assessment of Safety-Related Fuses Used in Low and Medium Voltage Applications in Nuclear Power Plants," states that fatigue of fuse holders can typically occur due to elevated temperature, mechanical stress, and repeated insertion and removal of fuses. The fuse holders subject to aging management review are located indoors with normal ambient temperatures of 70 to 90°F (104°F maximum). There are no significant sources of heat in close proximity to the fuse holders such that elevated ambient temperatures are expected. Therefore, fatigue due to elevated ambient temperature is not an applicable aging effect. Fatigue related to mechanical stress or repeated insertion and removal is evaluated under Mechanical Stress and Electrical Transients below. Fatigue related to thermal cycling is evaluated under Ohmic Heating and Thermal Cycling below.

Mechanical Stress and Electrical Transients

The fuse holders subject to aging management review are located in electrical enclosures and the fuses are not routinely removed and reinserted into the metallic clamps. Therefore, the fuse holder metallic clamps are not subject to repeated manipulation that could lead to mechanical fatigue. The stresses due to electrical transients are mitigated by the circuit protection provided by over-current devices for high-current applications. Mechanical stress due to electrical transients or faults is not considered credible because faults are so infrequent. The Columbia corrective action program (CAP) is used to document adverse equipment conditions and provides corrective actions associated with electrical transients and faults that cause the actuation of circuit protection devices. Therefore, mechanical stress and electrical transients are not applicable aging mechanisms.

Vibration

These electrical enclosures are wall-mounted, not mounted on rotating equipment. Therefore, vibration is not an applicable aging mechanism for the fuse holders in these enclosures.

Chemical Contamination and Corrosion

These fuse holders are located in electrical enclosures that have covers. The boxes are not exposed to weather as they are located indoors at Columbia. They are not exposed to chemical contamination or spills and such occurrences would be event-driven situations in any case. They are not exposed to mechanical stresses inside the boxes. They are not operated in an environment of industrial pollution or salt deposition due to Columbia's location in rural Washington state. The fuse holders are not subject to moisture or chemicals inside the electrical enclosures and do not experience a corrosive environment. Therefore, chemical contamination and corrosion are not applicable aging mechanisms for these fuse holders.

Ohmic Heating and Thermal Cycling

With respect to electrical transients and ohmic heating, these fuses are not heavily loaded and do not experience frequent electrical and thermal cycling. Therefore, ohmic heating and thermal cycling are not an applicable aging mechanisms for these fuse holders.

Oxidation

The Reactor Building Secondary Containment is maintained at approximately 70 to 90°F (104°F maximum) and 40% RH (residual humidity). Oxidation in this environment is not considered an applicable aging mechanism.

The Radwaste Battery Rooms are maintained at approximately 70°F (104°F maximum) and 40% RH. Oxidation in this environment is not considered an applicable aging mechanism.

Therefore, the fuse holders (metallic clamp) will not require an aging management program (following the guidance of NUREG-1801, Section XI.E5). The guidance of NUREG-1801, Section XI.E1 still applies to the insulating base of the in-scope fuse holders and Section XI.E6 still applies for the inspection of the cable terminations.

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION

RAI 3.1.2.3~01

Background:

Generic Aging Lessons Learned (GALL) Report Volume 1, Revision 1, Table 1 item 48 and GALL Report Volume 2, Revision 1, item IV.C1-1 indicate that steel and stainless steel Class 1 piping, fittings, and branch connections, which are less than Nominal Pipe Size (NPS) 4 and are exposed to reactor coolant, are subject to cracking due to stress corrosion cracking or intergranular stress corrosion cracking (stainless steel only) and thermal and mechanical loading. The GALL Report recommends the American Society of Mechanical Engineers (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 aging effect.

Issue:

License Renewal Application (LRA) Table 3.1.2-3, indicates that piping and fittings less than 4 inches exposed to reactor coolant are associated with LRA item 3.1.1-48 and the components are subject to cracking due to stress corrosion cracking and intergranular attack (IGA). LRA Table 3.1.2-3 also addresses, under item 3.1.1-48, the following components to manage stress corrosion cracking and intergranular attack in the same manner with the piping and fittings less than 4 inches exposed to reactor coolant: annubar, condensing unit, flow elements less than 4 inches, orifice less than 4 inches, tubing and valve bodies less than 4 inches. The applicant has indicated that these components are managed by the Small Bore Class 1 Piping Inspection Program and the BWR Water Chemistry Program.

In its review, the staff found the need to clarify why the applicant's Inservice Inspection (ISI) Program is not used to manage the aging effect for the components as recommended in the GALL Report although the applicant claimed that the line items are consistent with GALL Report item IV.C1-1. In addition, the staff found the need to clarify whether the cracking due to thermal and mechanical loading is also managed under the AMR line items in a consistent manner with GALL Report item IV.C1-1.

Request:

1. Clarify why the applicant's ISI Program is not used to manage cracking due to stress corrosion cracking and intergranular attack for the aforementioned components including piping and fittings less than 4 inches exposed to reactor coolant.

2. Clarify whether cracking due to thermal and mechanical loading is also managed under the aforementioned AMR line items in a consistent manner with GALL Report item IV.C1-1. If cracking due to thermal and mechanical loading is not managed

under the line items, provide justification why the aging effect due to the aging mechanisms is not managed for the components under the line items although the applicant claimed the consistency of the line items with the GALL Report.

Energy Northwest Response:

1. The ISI Program was not credited in the Columbia Generating Station (Columbia) LRA to manage cracking due to stress corrosion cracking (SCC) and IGA for components less than 4 inches NPS exposed to reactor coolant because the ASME Code, Categories B-J and B-M-1, require no volumetric examination of small bore components. However, the Columbia Risk Informed ISI program does include volumetric examination of selected small bore locations (3MS(9)-1, 3MS(9)-5, and 3MS(9)-7). As such, Columbia will add ISI to the aging management programs credited for management of SCC for these selected small bore components. See the amendment to the LRA provided in the enclosure to this letter.

2. Columbia opted to separate cracking due to SCC and cracking due to thermal and mechanical loading (referred to as cracking due to flaw growth) into separate line items, with cracking due to flaw growth managed only by the Small Bore Class 1 Piping Inspection. As stated above, the ISI program was not originally credited because ASME Categories B-J and B-M-1 require no volumetric examination. As discussed above, Columbia will add ISI to the aging management programs for cracking due to flaw growth of small bore components for the three aforementioned main steam (MS) lines. See the amendment to LRA Table 3.1.2-3 provided in the enclosure to this letter.

   The line items for cracking due to flaw growth of small bore components state that there is no comparable GALL line item. Columbia has not claimed consistency with NUREG-1801 IV.C1-1 for cracking due to flaw growth. These lines say "NA" for the NUREG-1801 Volume 2 item and the Table 1 item, and a Note H is used. Columbia is not claiming consistency with IV.C1-1 for cracking due to flaw growth because IV.C1-1 also lists BWR Water Chemistry as an applicable program. Columbia does not credit controlling water chemistry with the mitigation of cracking due to flaw growth.

LICENSE RENEWAL APPLICATION AMENDMENT 11

Section Number	Page Number	RAI Number
Table 3.1.1, Item 3.1.1-48	3.1-21	3.1.2.3-01
Table 3.1.2-3	3.1-114	3.1.2.3-01
Table 3.1.2-3	3.1-114a	3.1.2.3-01
Table 3.1.2-3	3.1-114b	3.1.2.3-01

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of NUREG-1801

Item Number	Component/Commodity	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-48	Steel and stainless steel Class 1 piping, fittings and branch connections < NPS 4 exposed to reactor coolant	Cracking due to stress corrosion cracking, intergranular stress corrosion cracking (for stainless steel only), and thermal and mechanical loading	Inservice Inspection (IWB, IWC, and IWD), Water chemistry, and One-Time Inspection of ASME Code Class 1 Small-bore Piping	No	Consistent with NUREG-1801. ~~Cracking of piping and in-line components is managed by the BWR Water Chemistry Program and the Small Bore Class 1 Piping Inspection.~~ Program This item is also used for cracking of reactor vessel components (bottom head, closure flange, shell rings, nozzles) managed by the Inservice Inspection (ISI) Program and the BWR Water Chemistry Program. A Note C is applied.

Cracking due to stress corrosion cracking of small bore components is managed by the BWR Water Chemistry Program, the Small Bore Piping Program, and the Inservice Inspection Program.
Cracking due to flaw growth (thermal and mechanical loading) of small bore components is managed by the Small Bore Piping Program and the Inservice Inspection Program. Note H is applied.

Table 3.1.2-3 Aging Management Review Results – Reactor Coolant Pressure Boundary									
Row No.	**Component Type**	**Intended Function(s)**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
172	Valve Body	Structural integrity	Stainless Steel	Air-Indoor Uncontrolled (External)	None	None	IV.E-2	3.1.1-86	A

Insert rows 173 - 186 from 3.1-114a and 3.1-114b.

Table 3.1.2-3 Aging Management Review Results – Reactor Coolant Pressure Boundary									
Row No.	**Component Type**	**Intended Function(s)**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
173	Flow Elements < 4 inches	Pressure Boundary	Stainless Steel	Reactor coolant (Internal)	Cracking – Flaw Growth	Inservice Inspection	NA	NA	H
174	Flow Elements <4 inches	Pressure Boundary	Stainless Steel	Reactor coolant (Internal)	Cracking – SCC/IGA`	Inservice Inspection	IV.C1-1	3.1.1-48	A
175	Orifices <4 inches	Pressure Boundary	Stainless Steel	Reactor coolant (Internal)	Cracking – Flaw Growth	Inservice Inspection	NA	NA	H
176	Orifices <4 inches	Pressure Boundary	Stainless Steel	Reactor coolant (Internal)	Cracking – SCC/IGA`	Inservice Inspection	IV.C1-1	3.1.1-48	A
177	Orifices <4 inches	Throttling	Stainless Steel	Reactor coolant (Internal)	Cracking – Flaw Growth	Inservice Inspection	NA	NA	H
178	Orifices <4 inches	Throttling	Stainless Steel	Reactor coolant (Internal)	Cracking – SCC/IGA`	Inservice Inspection	IV.C1-1	3.1.1-48	A
179	Piping & Fittings <4 inches	Pressure Boundary	Stainless Steel	Reactor coolant (Internal)	Cracking – Flaw Growth	Inservice Inspection	NA	NA	H

Table 3.1.2-3 Aging Management Review Results – Reactor Coolant Pressure Boundary									
Row No.	**Component Type**	**Intended Function(s)**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
180	Piping & Fittings <4 inches	Pressure Boundary	Stainless Steel	Reactor coolant (Internal)	Cracking – SCC/IGA`	Inservice Inspection	IV.C1-1	3.1.1-48	A
181	Piping & Fittings <4 inches	Pressure Boundary	Steel	Reactor coolant (Internal)	Cracking – Flaw Growth	Inservice Inspection	NA	NA	H
182	Valve Bodies < 4 inches	Pressure Boundary	CASS	Reactor coolant (Internal)	Cracking – Flaw Growth	Inservice Inspection	NA	NA	H
183	Valve Bodies < 4 inches	Pressure Boundary	CASS	Reactor coolant (Internal)	Cracking – SCC/IGA`	Inservice Inspection	IV.C1-1	3.1.1-48	A
184	Valve Bodies < 4 inches	Pressure Boundary	Stainless Steel	Reactor coolant (Internal)	Cracking – Flaw Growth	Inservice Inspection	NA	NA	H
185	Valve Bodies < 4 inches	Pressure Boundary	Stainless Steel	Reactor coolant (Internal)	Cracking – SCC/IGA`	Inservice Inspection	IV.C1-1	3.1.1-48	A
186	Valve Bodies < 4 inches	Pressure Boundary	Steel	Reactor coolant (Internal)	Cracking – Flaw Growth	Inservice Inspection	NA	NA	H