ENERGY NORTHWEST

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GO2-10-179

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 September 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. ML102450727)

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. Amendment 15 to Reference 1 is provided in the enclosure. This amendment contains a revision to commitment 5 in Table A-1 for the Buried Piping and Tanks Inspection Program. A new commitment to perform ultrasonic testing, when a technique has been demonstrated and documented in the Boiling Water Reactor Vessel Internals Program (BWRVIP), has been added as commitment 63 in Table A-1.

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, Engineering

Attachment: Response to Request for Additional Information

Enclosure: License Renewal Application Amendment 15

cc: NRC Region IV Administrator
NRC NRR Project Manager
NRC Senior Resident Inspector/988C
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. ML102450727)

RAI 3.1.2.3.1-1

Background:

In license renewal application (LRA) Table 3.1.2-1, the applicant stated that the steel nozzle (N06) safe-end extension (RHR/LPCI) exposed to air-indoor uncontrolled (external) does not require any aging effect to be managed. The related aging management review (AMR) line item cites generic note G, indicating that this environment is not in the GALL Report for the aging effects of this component and material combination. Also, the associated plant-specific note 0101 states that there is no identified aging effect for these components, based on their being exposed to indoor air, where temperature is >212°F.

Issue:

The staff noted that the applicant has listed in row item 313 of LRA Table 3.1.2 that reactor pressure vessel stabilizer brackets made of steel exposed to air-indoor uncontrolled (external) are being managed for "cracking - flaw growth" by the ASME Section XI ISI -IWB, IWC and IWD aging management program (AMP), and classified this with the Generic Note H. This classification does not appear consistent with the AMR item classified with the Generic Note G discussed above.

Request:

Justify why the treatment of these two AMR items is different for the same material exposed to same environment for managing the aging effect in one and not in the other item, and reconcile the differences.

Energy Northwest Response:

Thermal loading is normally attributed to the environment (internal or external) that provides the primary heat input; however, when a component has only one environment the thermal loading must be associated with that environment. These two items are different because the steel stabilizer brackets have no internal environment (LRA Table 3.1.2-1, Line Items 312 and 313), whereas the steel nozzle N6 safe end extension has both an internal and external environment (LRA Table 3.1.2-1, Line Items 142 – 146).

For the nozzle N6 safe-end extension the aging effect of cracking due to flaw growth is associated with the internal, reactor coolant, environment, which is the source of the temperature cycles loading of this safe end. (LRA Table 3.1.2-1, Line Item 142).

On the other hand, the reactor vessel stabilizer brackets are not exposed to reactor coolant. Their only environment is air-indoor uncontrolled. Even though the cyclic pressure/temperature loading of these brackets comes primarily from the reactor vessel temperature/pressure and not the ambient temperature/pressure, the loading is attributed to the only environment available, the external environment of air-indoor uncontrolled. (LRA Table 3.1.2-1, Line Item 313).

RAI 3.1.2.3.1-2

Background:

In LRA Tables 3.1.2-1 and 3.1.2-3 the applicant stated that various reactor vessel components of steel, steel with stainless steel cladding, stainless steel, and nickel alloys exposed to reactor coolant (internal) are being managed for "cracking - flaw growth" by the ASME Section XI ISI IWB, IWC and IWD Program. The related AMR line items cite generic note H, indicating that the aging effect is not in the GALL Report for this component, material, and environment combination. These components include: RPV shells or shell rings, various nozzles and associated safe-ends/thermal sleeves, penetrations, and support attachments/welds.

Issue:

The LRA refers to "Cracking - Flaw Growth" as a time dependent aging effect/mechanism being managed by the ASME Section XI ISI program. The applicant's usage (or intended meaning) of "Cracking - Flaw Growth" is not clear to the staff. Also, depending on the interpretation of "Flaw Growth," it would seem that these items should be addressed as "TLAA" which is covered under the GALL Report, instead of generic note "H" items.

Request:

(a) Clarify the meaning and intended usage of "Cracking - Flaw Growth" aging effect/mechanism.

(b) Identify any of the items for "Flaw Growth" (as associated with the Generic Note H of this AMR) in the current licensing basis (CLB) for flaw growth or flaw tolerance evaluations to analyze fatigue that involved the current operating term (40 years) and were determined to be relevant in making the safety determination? If so, justify the adequacy of aging management of applicable items by the ASME Section XI ISI - IWB, IWC and IWD Program (as Generic Note H items), or include these under time-limited aging analysis (TLAA) assessment.

Energy Northwest Response:

a) Energy Northwest uses the term "cracking – flaw growth" to refer to the cracking of components due to the cyclic loads imposed upon those components during operation. Service loads may result in the growth of pre-service flaws or initiation and growth of service-induced flaws. The most susceptible locations for flaw initiation and growth are the welded joints. Susceptibility is due to the variations in residual stresses and mechanical properties resulting from the various constituent zones within the joint. Therefore, cracking is an aging effect requiring management for the period of extended operation.

b) As stated above, this aging effect deals with the growth of pre-service flaws, or the initiation and growth of service induced flaws. This aging effect recognizes that these small, perhaps undetected, flaws may grow over time due to service loads. Inservice Inspection in accordance with the ASME Code will manage the growth of these flaws. If any of these flaws grow beyond the allowable flaw size they will then be dispositioned per the ASME code; and that disposition may or may not include flaw growth analyses. The only flaws discovered during Inservice Inspection that required flaw growth time-limited aging analyses are the reactor vessel shell indications discussed in LRA Section 4.7-1.

RAI 3.1.1.x-1

Background:

Cracking due to intergranular stress corrosion cracking (IGSCC) has occurred in small- and large-diameter boiling water reactor (BWR) piping made of austenitic stainless steels and nickel alloys. The IGSCC has also occurred in a number of vessel internal components, such as core shrouds, access hole covers, top guides, and core spray spargers (NRC Bulletin 80-13, NRC Information Notice [IN] 95-17, NRC Generic Letter [GL] 94-03, and NUREG-1544). Cracking due to thermal and mechanical loading have occurred in high pressure coolant injection (HPCI) piping (NRC IN 89-80) and instrument lines (NRC Licensee Event Report [LER] 50-249/99-0031). Jet pump BWRs are designed with access holes in the shroud support plate at the bottom of the annulus between the core shroud and the reactor vessel wall. These holes are used for access during construction and are subsequently closed by welding a plate over the hole. Both circumferential (NRC IN 88-03) and radial cracking (NRC IN 92-57) have been observed in access hole covers.

Issue:

Columbia Generating Station (CGS) has a jet-pump BWR designed with access holes in the shroud support plate which were closed by a welded cover plate. In this case one of the plates is welded only from the top and the plate material is austenitic stainless steel. This has the potential for IGSCC from the bottom where crevice conditions exist, requiring augmentation of the ASME Section XI ISI – IWB, IWC and IWD Program. In contrast to these plant conditions, the applicant, in its LRA Table 3.1.1 Item 3.1.1-49, states that access hole covers were modified to eliminate the crevice and that the component material is nickel alloy.

Request:

Clarify and reconcile the actual plant conditions for the access hole welded cover plates and the LRA Table 3.1.1 Item 3.1.1-49. Justify the absence of any augmented inspection plan for the creviced location(s) and provide the method and basis for monitoring and inspection for the potential IGSCC of these locations such that their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21 (a)(3).

Energy Northwest Response:

The access hole covers at Columbia are nickel alloy and stainless steel. One of the two access hole covers is welded directly to the nickel alloy shroud support. This access hole cover is nickel alloy and the weld between the cover and the shroud support is nickel alloy. This joint has been welded from both sides such that there is no crevice.

The other access hole cover is raised above the shroud support. A nickel alloy adapter ring is welded to the nickel alloy shroud support. The adapter ring to shroud support weld is nickel alloy and has been welded from both sides such that there is no crevice. A stainless steel riser ring is welded to the nickel alloy adapter ring with a nickel alloy weld that has been welded from both sides such that there is no crevice. A stainless steel access hole cover has been welded to the top of the stainless steel riser ring using a stainless steel weld. This stainless steel weld between two stainless steel parts has only been welded from the top and has an inherent crevice on the underside.

As stated in LRA Table 3.1-1, Item 3.1.1-49, the access hole covers were modified during plant construction to eliminate the crevices by back welding the crevices and installing a modified cover configuration. The Columbia access hole covers have no crevice behind the welds in the nickel alloy material or in the region of the shroud support plate.

The Columbia access hole covers are inspected by EVT-1 in accordance with BWRVIP guidelines on a six year frequency that coincides with the ASME Code inspections for access hole covers. A baseline inspection to BWRVIP guidelines was performed during Refueling Outage R18 (2007). Energy Northwest performs inspections of all welds associated with the access hole covers in accordance with the Inservice Inspection Program, augmented per BWRVIP guidelines, even though the only creviced weld is the stainless steel weld.

Energy Northwest is committed to inspect the creviced access hole cover per the BWRVIP guidance. When an ultrasonic testing (UT) technique has been demonstrated and documented by the BWRVIP, Columbia will perform those inspections using UT.

Amendment 15 addressing the required changes is provided in the enclosure to this letter.

RAI 3.3.1.68-1

Background:

LRA Table 3.3.1, item 3.3.1-68 addresses steel piping, piping components, and piping elements and item 3.3.1-70 addresses copper alloy piping, piping components, and piping elements exposed to raw water (internal) which are being managed for loss of material due to pitting, crevice, and microbiologically influenced corrosion (MIC), and fouling. To manage these aging effects, in LRA Table 3.3.2-22, the applicant credits the Diesel-Driven Fire Pumps Inspection Program (B.2.18) for the components in the fire protection system, and in LRA Tables the applicant credits the Monitoring and Collection Systems Inspection Program (B.2.41) for the components in the fuel pool cooling, plant sanitary drains, and reactor closed cooling water systems.

For line items 3.3.1-68 and 3.3.1-70, the GALL Report recommends using GALL AMP XI.M27 "Fire Water System" which recommends performing wall thickness evaluations of system components using nonintrusive volumetric testing or plant maintenance visual inspections of the internal surfaces to ensure that aging effects are being adequately managed. GALL AMP XI.M27 recommends that these inspections be performed before the end of the current operating term and at plant-specific intervals thereafter during the period of extended operation to ensure that degradation will be detected before the loss of intended function.

Issue:

The staff noted that the Diesel-Driven Fire Pumps Inspection Program and the Monitoring and Collection Systems Inspection Programs propose to manage the aging of steel and copper alloy piping, piping components, and piping elements through the use of one-time inspections involving a combination of established volumetric and visual examination techniques that will detect and characterize the conditions on the internal surfaces of subject mechanical components that are exposed to raw water (or antifreeze). It is not clear to the staff how these programs are adequate to manage loss of material for these components given that the GALL Report recommends periodic inspections to ensure that aging effects are being adequately managed and the system maintains its intended function during the period of extended operation.

Request:

Justify how the Diesel-Driven Fire Pumps Inspection and Monitoring and Collection Systems Inspection Programs, which are both one-time inspection programs, are adequate to manage loss of material and reduction in heat transfer for piping and components in the fire protection, fuel pool cooling, plant sanitary drains, and reactor closed cooling water systems in place of a periodic inspection program as recommended by the GALL Report.

Energy Northwest Response:

Based on a teleconference with the NRC Project Manager and other NRC staff on October 26, 2010, Energy Northwest is re-evaluating the use of one-time inspections described in the License Renewal Application. A comprehensive response to this issue will be provided under a separate cover letter. The information related to this request for additional information will be provided at that time.

RAI 3.4.2.3-1

Background:

In LRA Table 3.4.2-3, row number 33, the applicant proposes to manage loss of material for the external surfaces of steel piping exposed to uncontrolled indoor air using its Buried Piping and Tanks Inspection Program. The applicant cites plant-specific note 0408 which states that the carbon steel piping from the condensed storage tank (CST) is buried and is enclosed in guard pipe. The applicant also cites generic note E and line item 3.4.1-28. The GALL Report recommends GALL AMP GALL AMP XI.36 "External Surfaces Monitoring" to ensure that these aging effects are adequately managed.

Issue:

The staff notes that GALL AMP XI.36 "External Surfaces Monitoring" recommends periodic direct visual inspections of the surfaces managed by the program. The staff also notes that the applicant's Buried Piping and Tanks Inspection Program provides for visual inspections of the external surfaces of buried piping and tanks to determine coating integrity, but does not include access to or direct inspection of the external surfaces of buried pipe enclosed in an outer guard pipe. The staff further notes that the applicant's Buried Piping and Tanks Inspection Program does not include flow testing, pressure testing, or any other means to manage aging for piping within a guard pipe. It is unclear to the staff how the buried piping within a guard pipe will be adequately managed by the Buried Piping and Tanks Inspection Program.

Request:

Explain how the external surface of the underground piping enclosed in an outer guard pipe will be adequately managed for loss of material.

Energy Northwest Response:

The Condensate (Nuclear) (COND) System pipe runs through the CST foundation mat before it enters the ground, and then runs underground before entering the guard pipe. The guard pipe is sealed at each end with a T.D. Williamson U-seal or equivalent, which prevents moisture and soil from entering the space between the guard pipe and the COND pipe. The COND pipe runs within the guard pipe at a downward slope toward the Service Building where a watertight boot seal is provided between the guard pipe and the building wall. The COND pipe is coated with asbestos coal tar saturated felt, in accordance with AWWA C203. Contact between the COND pipe and the guard pipe is prevented by the use of insulating cradles.

The Buried Piping and Tanks Inspection Program will be enhanced to include one visual inspection to include the external coating on the COND pipe, which is steel hazmat piping, within the 10-year period prior to entering the period of extended operation, and one similar visual inspection in each 10 year-period after entering the period of extended operation. Evidence of damaged coating, or of coating defects, will be documented for further evaluation through the corrective action program. Amendment 15 to include the LRA revision is included in the enclosure.

RAI 3.3.2.2.3.3 -1

Background:

The GALL Report, Table 3 item 6 states that cracking due to stress corrosion cracking could occur in stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust. The GALL Report further states that these components require a further evaluation of a plant-specific aging management program to ensure that these aging effects are adequately managed. The LRA Section 3.3.2.2.3.3 states that during normal plant operations, diesel exhaust piping, piping components, and piping elements are exposed to outdoor air and are only exposed to diesel exhaust infrequently and for short durations. The LRA further states that due to these infrequent and short duration exposures, stress corrosion cracking is not identified as an aging effect requiring management for stainless steel diesel engine exhaust components.

Issue:

Stress corrosion cracking is a potential aging affect for stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust as indicated in the GALL Report. While there is an initiation period required for stress corrosion cracking to occur, it will depend on the material and environment. The LRA does provide enough information to rule out stress corrosion cracking of the stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust.

Request:

1. Clarify how stress corrosion cracking was quantitatively ruled out by providing additional information on the actual cumulative exposure time that the stainless steel diesel exhaust components are expected to be subjected to diesel exhaust greater than 60°C (140 °F) during the total period of extended operation.

2. Clarify what type of stainless steel is used in the diesel exhaust and provide the technical basis that substantiates the claim that the diesel exhaust piping, piping components, and piping elements are not susceptible to stress corrosion cracking under the cumulative exposure time during the period of extended operation.

Energy Northwest Response:

1. The diesel air compressor (DSA-C-2C) is a backup to the electric air compressor (DSA-C-1C) and only operates infrequently. There is no tracking of run time for DSA-C-2C. An estimate of annual run time for DSA-C-2C was made based on historical out-of-service time for DSA-C-1C (lead compressor) and maintenance activities that would cause a run of the diesel air compressor for post maintenance testing. The result of this estimate is that DSA-C-2C is expected to operate approximately 45 hours per year.

2. As stated in LRA section 3.3.2.2.3.3, with the exception of the flexible connection for the High Pressure Core Spray (HPCS) diesel compressor (DSA-C-2C), diesel exhaust piping, piping components, and piping elements are steel, for which cracking due to SCC is not an applicable aging effect.

LRA Table 3.3.1, item number 3.3.1-06 states that the exhaust piping, piping components and piping elements are steel. Also, LRA Table 3.3.2-16 line items 27 and 28 list the exhaust piping for the Diesel (Engine) Exhaust System as steel. This material identification is supported by Columbia Design Specifications which state that the diesel exhaust piping for HPCS, Div. I & Div. II diesel engines is ASTM A106 Gr. B (carbon steel).

The flexible connection for the HPCS diesel compressor (DE-FLX-5) is the only stainless steel component exposed to diesel exhaust. The flexible connection is type 304 and 321 stainless steel. LRA Table 3.3.2-16 line item 11 evaluated this component as stainless steel. This flexible connection is located near the compressor for the HPCS diesel where moisture collection is unlikely. In addition, this flexible connection is oriented in the vertical position where moisture will not accumulate. A review of plant operating experience has not identified instances of cracking in diesel exhaust components. Therefore, cracking due to SCC was not an aging effect requiring management for the stainless steel components in the diesel systems that are exposed to the air/gas environment. However, to conservatively ensure that cracking due to SCC is not occurring in the stainless steel flexible connection exposed to infrequent diesel exhaust, the Diesel Systems Inspection will be credited.

Columbia LRA Section 3.3.2.2.3.3, Table 3.3.1-06, Table 3.3.2-16, Section A.1.2.17, and Section B.2.17 are revised in Amendment 15 for clarification.

RAI 3.3.2.2.7.3-1

Background:

The GALL Report, Table 3 item 18 states that loss of material due to general (steel only), pitting, and crevice corrosion could occur for steel and stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust. The GALL Report further states that these components require a further evaluation of a plant-specific aging management program to ensure that these aging effects are adequately managed.

Issue:

The LRA Section 3.3.2.2.7.3 states that during normal plant operations, diesel exhaust piping, piping components, and piping elements are exposed to outdoor air and are only exposed to diesel exhaust infrequently and for short durations. The LRA further states that the loss of material will be managed by the Diesel Systems Inspection or the Diesel-Driven Fire Pumps Inspection Programs. It is not clear to the staff how the Diesel System Inspection or the Diesel-Driven Fire Pumps Inspection Programs, which is a one-time inspection program, will appropriately manage this aging effect.

Request:

Provide additional information on the technical basis for how the Diesel System Inspection and the Diesel-Driven Fire Pumps Inspection Programs will adequately managing loss of material for steel and stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust. Secondly, provide additional information why a program with a periodic inspection is not being used to manage this aging effect.

Energy Northwest Response:

Based on a teleconference with the NRC Project Manager and other NRC staff on October 26, 2010, Energy Northwest is re-evaluating the use of one-time inspections described in the License Renewal Application. A comprehensive response to this issue will be provided under a separate cover letter. The information related to this request for additional information will be provided at that time.

RAI 3.3.2.2.7.3-2

Background

The GALL Report, Table 3 item 18 states that loss of material due to general (steel only), pitting, and crevice corrosion could occur for steel and stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust. The GALL Report further states that these components require a further evaluation of a plant-specific aging management program to ensure that these aging effects are adequately managed. The LRA Section 3.3.2.2.7.3 states that during normal plant operations, diesel exhaust piping, piping components, and piping elements are exposed to outdoor air and are only exposed to diesel exhaust infrequently and for short durations. The LRA further states that the loss of material will be managed by the Diesel Systems Inspection or the Diesel-Driven Fire Pumps Inspection Programs, which are one-time inspection programs. The GALL Report states that the OneTime Inspection Program is used to verify the effectiveness of an AMP or may also be used to provide additional assurance that aging that has not yet manifested itself is not occurring. The GALL Report states that the One-Time Inspection Program may also be used to provide additional assurance that the evidence of aging shows that the aging is so insignificant that an AMP is not warranted.

Issue:

That staff noted that the Diesel Systems Inspection or the Diesel-Driven Fire Pumps Inspection Programs (i.e., One-Time Inspection Programs) are not used to verify the effectiveness of an AMP as recommended by GALL Report. The staff further noted these programs to provide assurance that aging that has not yet manifested or that the evidence of aging is so insignificant that an AMP is not warranted. However, the applicant has not indicated that corrosion of the diesel exhaust piping, piping components, and piping elements has not previously occurred.

Request:

Provide additional information on the operating experience of the diesel exhaust piping, piping components, and piping elements indicating if corrosion has been observed in the past. If operating experience does reveal corrosion of the diesel exhaust piping, piping components, and piping elements, provide additional information on why the Diesel Systems Inspection or the Diesel-Driven Fire Pumps Inspection Programs are appropriate to manage the aging of these components.

Energy Northwest Response:

Based on a teleconference with the NRC Project Manager and other NRC staff on October 26, 2010, Energy Northwest is re-evaluating the use of one-time inspections described in the License Renewal Application. A comprehensive response to this issue will be provided under a separate cover letter. The information related to this request for additional information will be provided at that time.

RAI 3.5.2.1-1

Background:

In LRA Table 3.5.2-1, row number 9, the applicant states that stainless steel drywell sump liners exposed to raw water are being managed for loss of material by the Structures Monitoring and BWR Water Chemistry Programs. The AMR line item cites generic note J and plant specific note 0508, which states that, in addition to the Structures Monitoring Program as the applicable AMP, the BWR Water Chemistry Program is also credited with the elimination of excessive chlorides and sulfates from the water. In LRA Section 2.4.1, the applicant also states that it has two drywell sumps; one for unidentified leakage, and one for identified leakage. The applicant further states that the floor drain sump collects unidentified leakage from sources within the drywell, such as valve stem, and control rod drive (CRD) leakage; and the drywell equipment drain sump receives identified reactor coolant leakage from the reactor vessel head flange vent and pump seal leak-off lines.

The staff notes that the applicant's BWR Water Chemistry Program includes monitoring and control of contaminants, such as chlorides and sulfates, in primary and secondary water in accordance with Electrical Power Research Institute water chemistry guidelines. However, the staff also notes that water collected by the drywell sumps include normal leakage which could have been exposed to contaminants in the drywell as it drains from the leak point to the drywell sump. The staff further notes that closed cooling water leakage from the drywell cooling units, which is not monitored by the BWR Water Chemistry Program, could also enter the drywell sumps.

Issue:

The configuration of the floor drain and drywell equipment drain sumps do not prevent the intrusion of water that was part of the primary water system but has been exposed to contaminants or water from the closed cooling water system that is not monitored by the BWR Water Chemistry Program. It is unclear to the staff how the BWR Water Chemistry Program is being used to reduce chlorides and sulfates in the water being collected by the drywell sumps in order to manage loss of material for the drywell sump liners.

Request:

Explain how the BWR Water Chemistry Program is being used to manage loss of material for the drywell sump liners.

Energy Northwest Response:

Energy Northwest agrees with the RAI statement that the configuration of the floor drain and drywell equipment drain sumps do not prevent the intrusion of water that was part of the primary water system but has been exposed to contaminants or water from the closed cooling water system that is not monitored by the BWR Water Chemistry Program. The BWR Water Chemistry Program is not intended to be used to manage loss of material for the drywell sump liners; the Structures Monitoring Program is the program that is credited for managing loss of material. The BWR Water Chemistry Program was credited since it reduces excessive chlorides and sulfates from the water received in the drywell sumps that originates from the primary water system. Thus, this program provides a 'defense-in-depth' by reducing the contaminant parameter for stress corrosion cracking (SCC) or intergranular attack (IGA) to occur in the stainless steel drywell sump liners.

Drywell sumps were evaluated assuming a raw water environment as indicated in LRA Table 3.5.2-1 row number 9. The two drywell sumps catch leakage from fluid systems within the primary containment and are gravity drained out of primary containment to sumps in the reactor building via drain piping in each sump. The sump liners are exposed to liquid near the sump bottom due to the configuration of the drain pipes. The drain pipes rise above the bottom of the associated sump as perforated pipe in the Floor Drain Radioactive (FDR) sump or with a perforated cap in the Equipment Drain

Radioactive (EDR) sump that will allow some volume of water to remain in each sump. Thus, the drywell sump liners are assumed wet for license renewal evaluation. Since system leakages can be from the CRDs, valve flange leakage, closed cooling water system drywell cooling unit drains, or valve packing leaks; a raw water environment is assigned. For the purposes of aging management review (AMR) at Columbia and for a conservative identification of aging effects requiring evaluation, a raw water environment was assigned so the possibility of occurrence of an aging effect is not eliminated.

The LRA Table 3.5.2-1, row number 9 cited generic note J because NUREG-1801 Revision 1 Table III.A1 for Group 1 structures (BWR Reactor Building) does not contain a line item for stainless steel structures exposed to a raw water environment. The only steel line item III.A1-12 credits the Structure Monitoring Program for managing loss of material in an air-indoor or air-outdoor environment.

The AMR determination for cracking due to SCC or IGA for the stainless steel drywell sump liners was determined not applicable since two out of the three parameters for SCC or IGA to occur were determined not significant. The three parameters for SCC or IGA aging mechanisms to occur are contaminant (chloride content exceeds 1 ppm) with temperature greater than 140°F or in sea/brackish water environments regardless of temperature. The drywell sump water chloride content can exceed 1 ppm since building sumps receive leakage from systems and floor drains. The associated EDR and FDR system piping into and out of the sump have normal operating temperature of 120°F which is less than the 140°F temperature threshold. Also, the applied and residual stresses on these sump liners embedded in concrete is much lower than that of stainless steel components having a pressure boundary intended function or are designed for transient loads. Review of plant-specific and industry operating experience did not identify instances of SCC or IGA on building sump liner or cracking of sump liner. This was the reason that the aging effect requiring management "Cracking" was not shown in LRA Table 3.5.2-1, row number 9.

Although the BWR Water Chemistry Program was not needed to manage cracking due to SCC or IGA since two of the three factors for SCC or IGA to occur were determined to be non-significant based on AMR determination, the BWR Water Chemistry Program was previously credited since it reduces excessive chlorides and sulfates from the water received in the drywell sumps and thus reduces the contaminant parameter for SCC or IGA to occur in the stainless steel drywell sump liners. This is noted in LRA Plant Specific Note 0508 which states "In addition to Structures Monitoring Program as AMP, the BWR Water Chemistry Program is credited with the elimination of excessive chlorides and sulfates from the water."

However, in order to clarify that the BWR Water Chemistry Program is not being used to manage loss of material for the drywell sump liners, LRA Table 3.5.2-1 Row 9 on page 3.5-81 and plant-specific note 0508 on page 3.5-138 are amended as noted in amendment 15 to the LRA as provided in the enclosure.

RAI B.2.43-3

Background

SRP-LR, Appendix A.1.1.2.3.5, states that monitoring and trending activities should be described and should provide predictability of the extent of degradation in order to effect timely corrective or mitigative actions. It also states that the methodology for analyzing inspection results against acceptance criteria should be described.

Issue:

The Potable Water Monitoring Program's "monitoring and trending" program element provides information on monitoring activities for water quality; however, there is no description of monitoring or trending activities associated with the planned enhancement to the program for periodic inspection activities.

Request:

Provide information regarding monitoring and trending activities associated with the planned program enhancement for periodic inspection activities, or provide a basis for not monitoring and trending these periodic inspection results.

Energy Northwest Response:

Information regarding monitoring and trending activities associated with the planned program enhancement for periodic inspection activities was previously provided in LRA Amendment 3, submitted via letter, GO2-10-124, dated August 26, 2010, DW Coleman (EN) to NRC.

> The Potable Water Monitoring Program will also be used to characterize conditions (inside piping and components) and to determine if, and to what extent, further actions may be required. The program will include increasing the inspection sample size and location if degradation is detected. The program will also include engineering evaluation of the inspection results to determine if the inspection frequency can be reduced or needs to be increased.

RAI B.2.43-4

Background:

SRP-LR, Appendix A.1.1.2.3.10 states that operating experience information, including past corrective actions which result in program enhancements, should be considered. It continues by stating this information can show where an existing program failed to intercept aging degradation in a timely manner, resulting in appropriate program enhancements, and the information should provide objective evidence to support the conclusion that the effects of aging will be managed so that intended function(s) will be maintained.

Issue:

The Potable Water Monitoring Program's "detection of aging effects" element states that based on operating experience, it is necessary that inspections be conducted at least one every 5 years, and to include components in the potable cold water, potable hot water and reactor building outside air systems. The program's "operating experience" element states that there have been recurrent problems mainly related to PVC piping, which are not in-scope for license renewal and that none of the leakage problems have occurred where they could have affected safety-related equipment due to leakage or spray. However, based on the staff's onsite review of operating experience involving corrosion or indications of corrosion, even though these components may not have been in-scope for license renewal, they are indicative of corrosion occurring in both copper and iron alloys in the potable water system. It was not clear to the staff if the operating experience provides objective evidence to support the conclusion that the effects of aging will be managed adequately by a periodic inspection of the potable water system every 5 years so that intended function(s) will be maintained.

Request:

Provide additional information on the technical basis for conducting periodic inspections at 5 year intervals; including relevant operating experience for components that have the same material, environment, and aging affects, consistent with the in-scope components in the potable water system.

Energy Northwest Response:

There are two programs in NUREG-1801 that specify five-year inspection intervals. These programs are NUREG-1801, Section XI.S2, "ASME Section XI, Subsection IWL" and NUREG-1801, Section XI.S7, "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants." Other NUREG-1801 programs specify ten-year intervals, and still others specify "plant-specific" inspection intervals. A five-year interval is reasonable, for the plant-specific Potable Water Monitoring Program, based on the NUREG-1801 guidelines for other programs and plant operating experience which has not identified leaks within the in-scope portions of the potable water system, and included a system wide evaluation in 2001. In addition, the program includes an enhancement to conduct at least one inspection within the 10-year period prior to the period of extended operation and at five-year intervals thereafter, as described in LRA Section B.2.43. As stated in letter GO2-10-124, the program will also include engineering evaluation of the inspection results to determine if the inspection frequency can be reduced or needs to be increased.

Furthermore, the program, as enhanced, provides reasonable assurance that the effects of aging will be managed such that components subject to aging management review will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation. All of the components that credit the Potable Water Monitoring Program have a 'Structural integrity" function, which is defined in LRA Table 2.0-1 as "Maintain structural and pressure boundary integrity to prevent adverse physical interaction with safety-related SSCs such that the safety-related SSCs might fail to perform their intended functions." Therefore, the focus of the program is on ensuring that leaks in metallic piping in areas that contain safety-related SSCs do not result in adverse physical interaction with safety-related SSCs, rather than on eliminating or minimizing leaks in potable water system components.

According to LRA Section B.2.43, operating experience shows that leakage has been a recurring problem in the Columbia potable water systems. These problems have been detected, and components have been isolated and repaired or replaced, in accordance with the corrective action program. None of the system leakage problems have occurred in portions of the systems that are within the Reactor Building and Radwaste Building (including corridors) where they could affect safety-related equipment due to leakage or spray. The majority of the leaks have been in the yard loop piping which is external to the power block structures and is buried. This piping is polyvinyl chloride (PVC) material which makes it susceptible to leaks due to changes in temperature related to location and environment. The piping in the Reactor Building and Radwaste Building (including corridors) is not exposed to the same environment (i.e., indoor air not soil) and is not of the same material (i.e., metallic not PVC).

Relevant operating experience for components of the same material, environment, and aging effects as potable water system components in the scope of license renewal includes the evaluation of system-wide corrosion problems in 2001 as a result of pinhole leaks identified in potable water copper tubing in the Deschutes Building, Kootenai Building, and the Snake River Warehouse. These buildings are not part of the Reactor Building or the Radwaste Building; and, the subject piping in the evaluation is not within the scope of license renewal. Additional leaks have been identified in metallic piping segments of the Potable Water System in areas other than areas that contain safety-related SSCs. These leaks have been identified and corrected as housekeeping items, during normal maintenance and operations activities, and did not require any additional corrective actions or evaluations. Such leaks are recorded in the corrective action process and do not show a negative trend that would indicate a need for additional actions during the current operating period in plant areas that contain safety-related SSCs. Leaks in in-scope portions of the potable water system have not manifested themselves as evidenced by operating experience. However, B.2.43 includes enhancement for periodic inspection activities and that the inspections be conducted at least once every five years in order to provide further assurance that aging of Potable Water System components in the scope of license renewal will not result in adverse spatial interactions with safety-related systems, structures and components.

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Section No.	Page No.	RAI Response
Table 3.1.1 Item 3.1.1-49	3.1-22	3.1.1.x-1
Table 3.1.1 Item 3.1.1-49	3.1-22a	3.1.1.x-1
Table 3.1.2-2 Items 68, 69, 70	3.1-91	3.1.1.x-1
Table 3.1.2-2 Items 71, 72, 73	3.1-92	3.1.1.x-1
Table 3.1.2-2 Note 110	3.1-116	3.1.1.x-1
3.3.2.2.3.3	3.3-51	3.3.2.2.3.3-1
Table 3.3.1 Item 3.3.1-06	3.3.-59	3.3.2.2.3.3-1
Table 3.3.2-16 Row 11	3.3-195	3.3.2.2.3.3-1
Table 3.5.2-1 Row 9	3.5-81	3.5.2.1-1
Table 3.5.2-1 Note 508	3.5-138	3.5.2.1-1
A.1.2.5	A-9	3.4.2.3-1
A.1.2.5	A-9a	3.4.2.3-1
A.1.2.17	A-13	3.3.2.2.3.3-1
A.1.2.33	A-19	3.1.1.x-1
A.1.2.33	A-19a	3.1.1.x-1
Table A-1 Item 5	A-43	3.4.2.3-1
Table A-1 Item 5	A-43a	3.4.2.3-1
Table A-1 Item 63	A-68b	3.1.1.x-1
B.2.5	B-39	3.4.2.3-1
B.2.5	B-39a	3.4.2.3-1
B.2.5	B-40	3.4.2.3-1
B.2.5	B-40a	3.4.2.3-1
B.2.17	B-77	3.3.2.2.3.3-1
B.2.17	B-78	3.3.2.2.3.3-1
B.2.17	B-79	3.3.2.2.3.3-1

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Section No.	Page No.	RAI Response
B.2.23	B-136	3.1.1.x-1
B.2.23	B-136a	3.1.1.x-1

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
3.1.1-49	Nickel alloy core shroud and core plate access hole cover (welded covers)	Cracking due to stress corrosion cracking, intergranular stress corrosion cracking, irradiation-assisted stress corrosion cracking	Inservice Inspection (IWB, IWC, and IWD), Water Chemistry, and, for BWRs with a crevice in the access hole covers, augmented inspection using UT or other demonstrated acceptable inspection of the access hole cover welds	No	Consistent with NUREG-1801. ~~Cracking of the welded access hole covers is managed by the Inservice Inspection (ISI) Program and the BWR Water Chemistry Program.~~ The access hole covers are of the retrofit (welded with crevices) design, but were modified during RPV construction to eliminate the crevice by back welding the crevices and installing a modified cover configuration.
3.1.1-50	High-strength low alloy steel top head closure studs and nuts exposed to air with reactor coolant leakage	Cracking due to stress corrosion cracking and intergranular stress corrosion cracking	Reactor Head Closure Studs	No	Consistent with NUREG-1801. Cracking of the reactor head closure studs is managed by the Reactor Head Closure Studs Program.

Replace with Insert A on Page 3.1-22a

in the region of the shroud support plate

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Insert A to page 3.1-22

Cracking of the welded access hole covers is managed by the Inservice Inspection (ISI) Program, which includes augmented inspection of access hole covers in accordance with BWRVIP guidelines, and the BWR Water Chemistry Program.

Table 3.1.2-2 Aging Management Review Results - Reactor Vessel Internals									
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**
65	Shroud	Floodable volume	Stainless Steel	Reactor Coolant with Neutron Fluence (Internal)	Cracking - Fatigue	TLAA	IV.B1-14	3.1.1-05	A
66	Shroud	Floodable volume	Stainless Steel	Reactor Coolant with Neutron Fluence (Internal)	Loss of Material	BWR Water Chemistry	IV.B1-15	3.1.1-47	A
67	Shroud	Floodable volume	Stainless Steel	Reactor Coolant with Neutron Fluence (Internal)	Loss of Material	Inservice Inspection	IV.B1-15	3.1.1-47	A
68	Shroud Support Access Hole Covers	Floodable volume	Nickel Alloy	Reactor Coolant (Internal)	Cracking - Flaw Growth	BWR Vessel Internals	N/A	N/A	H
69	Shroud Support Access Hole Covers	Floodable volume	Nickel Alloy	Reactor Coolant (Internal)	Cracking - SCC/IGA	BWR Water Chemistry	IV.B1-5	3.1.1-49	A
70	Shroud Support Access Hole Covers	Floodable volume	Nickel Alloy	Reactor Coolant (Internal)	Cracking - SCC/IGA	Inservice Inspection	IV.B1-5	3.1.1-49	A

and Stainless Steel

0110

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Table 3.1.2-2 Aging Management Review Results - Reactor Vessel Internals									
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**
71	Shroud Support Access Hole Covers	Floodable volume	Nickel Alloy	Reactor Coolant (Internal)	Cracking - Fatigue	TLAA	IV.B1-14	3.1.1-05	A
72	Shroud Support Access Hole Covers	Floodable volume	Nickel Alloy	Reactor Coolant (Internal)	Loss of Material	BWR Water Chemistry	IV.B1-15	3.1.1-47	A
73	Shroud Support Access Hole Covers	Floodable volume	Nickel Alloy	Reactor Coolant (Internal)	Loss of Material	Inservice Inspection	IV.B1-15	3.1.1-47	A
74	Steam Dryer	Structural integrity	Stainless Steel	Reactor Coolant (Internal)	Cracking - FIV	BWR Vessel Internals	IV.B1-16	3.1.1-29	E
75	Top Guide	Support	Stainless Steel	Reactor Coolant with Neutron Fluence (Internal)	Cracking - Flaw Growth	BWR Vessel Internals	N/A	N/A	H
76	Top Guide	Support	Stainless Steel	Reactor Coolant with Neutron Fluence (Internal)	Cracking - SCC/IASCC	BWR Vessel Internals	IV.B1-17	3.1.1-44	A

and Stainless Steel

Plant-Specific Notes:	
0101	NUREG-1801 Chapter IV does not list indoor air as an environment for carbon steel or low alloy steel components such as the vessel shell. This aging management review finds that there is no identified aging effect for these components whose temperature is >212 °F based on their being exposed to indoor air.
0102	Only high strength bolting (yield strength > 150 ksi) and bolting with sulfide containing lubricants, whether carbon or stainless steel, are susceptible to SCC.
0103	NUREG-1801 item IV.C1-1 covers multiple types of cracking in multiple sizes of components. IV.C1-1 lists three programs: ISI, BWR Water Chemistry, and Small Bore Piping. BWR Water Chemistry does not affect cracking due to flaw growth (loading) and Small Bore Piping is not applicable for the reactor vessel. Therefore, using ISI as the aging management program is a match to NUREG-1801.
0104	The internal attachments inside the vessel only have an external environment, which is reactor coolant.
0105	The aging effect of loss of material due to flow accelerated corrosion applies only to Main Steam, Reactor Core Isolation Cooling, Reactor Feedwater, Reactor Recirculation, Reactor Water Clean-Up, and Residual Heat Removal system piping. Other areas of the reactor coolant pressure boundary do not have the conditions necessary for flow accelerated corrosion.
0106	The aging effect determination for the Air-indoor uncontrolled (Internal) environment is the same as the NUREG-1801 determination for an Air-indoor uncontrolled (External) environment because the material is the same and the internal environment is equivalent to the external environment evaluated in the NUREG-1801 item Monitoring of the external surface condition will be used to characterize the aging effects on the internal surfaces.
0107	GALL item IV.B1-4 is for nickel alloy and the safe ends are stainless steel. However, nickel alloy and stainless steel are similar for cracking due to SCC/IGA. The same GALL item was used for both the nickel alloy nozzles and the stainless steel safe ends for consistency.
0108	The BWR Feedwater Nozzle Program manages cracking due to any mechanism for the feedwater nozzle assembly, including the nozzle, safe end, and thermal sleeve.
0109	Cracking of the N12, N13, and N14 nozzle to vessel weld is included because the weld is nickel alloy, whereas the nozzle is low alloy steel. For other aging effects, the weld is included with the nozzle.
0110	One of the two access hole covers has a modified configuration with a stainless steel top hat. The welds of both access hole covers to the shroud support plate are nickel alloy, backfilled to eliminate crevices.

However, to conservatively ensure that cracking due to stress corrosion cracking is not occurring in the stainless steel piping components exposed to infrequent diesel exhaust, the one-time Diesel Systems Inspection will be credited.

Section 3.3.2.2.3.3

W

stainless steel diesel engine exhaust components. ~~In addition~~, with the exception of the flexible connection for the HPCS diesel compressor, diesel exhaust piping, piping components, and piping elements are steel, for which cracking due to SCC is not an applicable aging effect.

3.3.2.2.4 Cracking due to Stress Corrosion Cracking and Cyclic Loading

The associated items in Table 3.3.1 (including 3.3.2.2.4.1, 3.3.2.2.4.2, 3.3.2.2.4.3, and 3.3.2.2.4.4) are applicable to PWRs only.

3.3.2.2.5 Hardening and Loss of Strength due to Elastomer Degradation

3.3.2.2.5.1 Components of Heating and Ventilation Systems

The HVAC systems contain elastomer flexible connections and elastomer mechanical sealants requiring aging management based on plant operating experience. Elastomer flexible connections and elastomer mechanical sealants subject to hardening and loss of strength in HVAC systems are managed by the External Surfaces Monitoring Program.

3.3.2.2.5.2 Spent Fuel Cooling and Cleanup Systems

There are no elastomer linings in the Fuel Pool Cooling System that are subject to AMR.

Elastomer flexible connections in the Diesel Cooling Water System refer to Table 3.3.1 item 3.3.1-12. Hardening and loss of strength of these flexible connections is managed by the Flexible Connection Inspection, which is a new one-time inspection to detect and characterize aging of these connections.

3.3.2.2.6 Reduction of Neutron-Absorbing Capacity and Loss of Material due to General Corrosion

The spent fuel racks contain a neutron-absorbing medium of boron carbide (B_4C) granular material bonded together to form plates. These plates are sealed in a stainless steel rack and are not exposed to treated water. Consequently, there are no aging effects requiring management for the neutron absorber material. The stainless steel around the neutron absorber is exposed to treated water and is susceptible to loss of material due to crevice and pitting corrosion. The BWR Water Chemistry Program is credited for aging management.

Insert A from Page 3.3-51a

3.3.2.2.7 Loss of Material due to General, Pitting, and Crevice Corrosion

3.3.2.2.7.1 Reactor Coolant Pump Oil Collection System

Columbia does not have a reactor coolant pump (reactor recirculation pump) oil collection system. Other components exposed to lubricating oil have loss of material mitigated by the Lubricating Oil Analysis Program with the Lubricating Oil Inspection verifying the effectiveness of the program.

The Diesel Systems Inspection is credited to conservatively ensure that cracking due to stress corrosion cracking is not occurring in the stainless steel piping components exposed to infrequent diesel exhaust.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of NUREG-1801

Item Number	Component/Commodity	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-06	Stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust	Cracking due to stress corrosion cracking	A plant specific aging management program is to be evaluated.	Yes, plant specific	~~Not applicable.~~ ~~As described in LRA Tables 3.3.2-16 and 3.3.2-22, exhaust piping, piping components and piping elements are steel.~~ Refer to Section 3.3.2.2.3.3 for further information.
3.3.1-07	PWR Only				
3.3.1-08	PWR Only				
3.3.1-09	PWR Only				
3.3.1-10	High-strength steel closure bolting exposed to air with steam or water leakage.	Cracking due to stress corrosion cracking, cyclic loading	Bolting Integrity The AMP is to be augmented by appropriate inspection to detect cracking if the bolts are not otherwise replaced during maintenance.	Yes, if the bolts are not replaced during maintenance	Not applicable. This item only applies to bolting for components addressed in items 3.3.1-07, 3.3.1-08, and 3.3.1-09 above, which are for a PWR only. Refer to Section 3.3.2.2.4 for further information.

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Table 3.3.2-16 Aging Management Review Results – Diesel (Engine) Exhaust System

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
10	Flexible Connection	Pressure boundary	Elastomer	Air-indoor uncontrolled (External)	None	None	VII.F4-6	3.3.1-11	I
11	Flexible Connection	Pressure boundary	Stainless Steel	Air-outdoor (Internal)	~~None~~ Cracking	~~None~~ Diesel Systems Inspection	~~N/A~~ VII.H2-1	~~N/A~~ 3.3.1-06	~~G~~ E 0322
12	Flexible Connection	Pressure boundary	Stainless Steel	Air-indoor uncontrolled (External)	None	None	VII.J-15	3.3.1-94	A
13	Flexible Connection	Pressure boundary	Steel	Air-indoor uncontrolled (Internal)	Loss of material	External Surfaces Monitoring	VII.I-8	3.3.1-58	C 0302
14	Flexible Connection (exhaust)	Pressure boundary	Steel	Air-outdoor (Internal)	Loss of material	Diesel Systems Inspection	VII.H2-2	3.3.1-18	E 0322
15	Flexible Connection	Pressure boundary	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VII.I-8	3.3.1-58	A
16	Heat Exchanger (shell) (Turbocharger Aftercooler)	Pressure boundary	Steel	Air-indoor uncontrolled (Internal)	Loss of material	External Surfaces Monitoring	VII.H2-3	3.3.1-59	A 0302
17	Heat Exchanger (shell) (Turbocharger Aftercooler)	Pressure boundary	Steel	Air-indoor uncontrolled (External)	Loss of material	External Surfaces Monitoring	VII.H2-3	3.3.1-59	A

Table 3.5.2-1 Aging Management Review Results - Primary Containment									
Row No.	**Component / Commodity**	**Intended Function[1]**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Volume 2 Item**	**Table 1 Item**	**Notes**
8	Drywell Head (including drywell head flanges, lifting lugs, support feet, and double o-rings)	EN, SPB, SSR	Carbon Steel/ Elastomer	Air - indoor	Loss of material	Inservice Inspection Program-IWE Appendix J Program	II.B2.1-1	3.5.1-05	A 0502
9	Drywell Sump Liners	SSR	Stainless Steel	Raw water	Loss of material	Structures Monitoring Program ~~BWR Water Chemistry Program~~	N/A	N/A	~~J~~ ~~0508~~
10	Equipment Hatch and CRD Removal Hatch (including flange gaskets and closure mechanisms)	EN, SPB, SSR	Carbon Steel/ Elastomer	Air - indoor	Loss of material	Inservice Inspection Program-IWE Appendix J Program Plant Technical Specification	II.B4-5 II.B4-6	3.5.1-17 3.5.1-18	A 0506
11	Penetrations (Mechanical and Electrical, primary containment boundary)	EN, SPB, SSR	Carbon Steel/ Elastomer	Air - indoor	Loss of material	Inservice Inspection Program-IWE Appendix J Program	II.B4-1	3.5.1-18	A 0505
12	Penetrations (Mechanical and Electrical, primary containment boundary)	EN, SPB, SSR	Stainless Steel	Air - indoor	None	Inservice Inspection Program-IWE Appendix J Program	N/A	N/A	I 0501, 0505

Plant-Specific Notes:	
0501	No applicable aging effects have been identified for the component type. However, the identified AMP will be used to confirm the absence of significant aging effects for the period of extended operation.
0502	NUREG-1801 item II.B2.1-1 indicates the moisture barrier, at the junction where the shell or liner becomes embedded, is subject to aging management activities in accordance with ASME Section XI, Subsection IWE requirements. Columbia drywell floor peripheral seal is made of stainless steel and is welded to the primary containment vessel and to the underside of the circular closure girder embedded in the drywell floor. There are no concrete to metal moisture barriers; therefore, the NUREG-1801 text regarding moisture barrier is not applicable.
0503	The refueling stainless steel bellows perform their functions during refueling preventing water from entering the drywell. The bellows are not subjected to cyclic loading during refueling. The normal environment experienced by the refueling bellows is warm, dry air, with short periods of demineralized water contact during refueling.
0504	Due to possibility of containment shell degradation from corrosion induced by a moist environment in sand pocket region, Columbia has committed to monitor humidity levels in this region. Columbia has implemented a procedure to survey the relative humidity of air drawn from within containment annulus sand pocket region.
0505	The process line penetrations are of welded steel construction without expansion bellows, gaskets, or sealing compounds. Electrical penetration assembly internal o-rings are sub-component of the electrical penetration and are included in this commodity group. Insulation for hot penetrations is addressed in bulk commodities.
0506	Elastomeric seals, gaskets, or o-rings are sub-part of the host component and their leak tightness is monitored by the Appendix J Program. Plant Technical Specification ensures that access airlocks and hatches maintain leak tightness in the closed position.
0507	In addition to Inservice Inspection Program-IWE and Appendix J Program as AMP, the BWR Water Chemistry Program is credited with the elimination of excessive chlorides and sulfates from the water.
0508	~~In addition to Structures Monitoring Program as AMP, the BWR Water Chemistry Program is credited with the elimination of excessive chlorides and sulfates from the water.~~
0509	Note C is used since NUREG-1801 only has an ASME Class 1 item for component in treated water. Component is ASME Class 2; the NUREG-1801 item is the closest match.

Replace strikeout text with "Not used."

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A.1.2.4 Bolting Integrity Program

The Bolting Integrity Program is a combination of existing activities that, in conjunction with other credited programs, address the management of aging for the bolting of mechanical components and structural connections within the scope of license renewal. The Bolting Integrity Program relies on manufacturer and vendor information and industry recommendations for the proper selection, assembly, and maintenance of bolting for pressure-retaining closures and structural connections. The Bolting Integrity Program includes, through the Inservice Inspection (ISI) Program, Inservice Inspection (ISI) Program – IWF, Structures Monitoring Program, and External Surfaces Monitoring Program, the periodic inspection of bolting for indications of degradation such as leakage, loss of material due to corrosion, loss of pre-load, and cracking due to stress corrosion cracking (SCC) and fatigue.

Replace deleted text with Insert A on page A-9a

A.1.2.5 Buried Piping and Tanks Inspection Program

~~The Buried Piping and Tanks Inspection Program manages the effects of loss of material due to corrosion on the external surfaces of piping and tanks exposed to a buried environment. The~~ Buried Piping and Tanks Inspection Program is a combination of a mitigation program (~~consisting of~~ protective coatings) and a condition monitoring program (consisting of visual inspections). Insert B from page A-9a

An inspection of buried piping will be performed within the 10-year period prior to entering the period of extended operation. An additional inspection of buried piping will be performed within 10 years after entering the period of extended operation.

The Buried Piping and Tanks Inspection Program is an existing program that requires enhancement prior to the period of extended operation.

Insert C from page A-9a

A.1.2.6 BWR Feedwater Nozzle Program

The BWR Feedwater Nozzle Program is an existing program that manages cracking due to stress corrosion cracking and intergranular attack (SCC/IGA) and flaw growth of the feedwater nozzles. The BWR Feedwater Nozzle Program is in accordance with ASME Section XI and NRC augmented requirements.

The BWR Feedwater Nozzle Program consists of: (a) enhanced inservice inspection in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWB, Table IWB 2500-1 (2001 edition including the 2002 and 2003 Addenda) and the recommendations of General Electric report NE-523-A71-0594-A [Reference A.1.4-1], and (b) system modifications, as described in FSAR Section 5.3.3.1.4.5, to mitigate cracking. The program specifies periodic ultrasonic inspection of critical regions of the feedwater nozzles.

Insert A to LRA Section A.1.2.5

The Buried Piping and Tanks Inspection Program manages the effects of loss of material due to corrosion on the external surfaces of piping, piping components and tanks exposed to a buried environment. The program also manages the effects of cracking, loss of material and loss of pre-load for bolting exposed to a buried environment.

Insert B

The Buried Piping and Tanks Inspection Program also manages the effects of loss of material due to corrosion on the external surfaces of the COND System piping that is below grade, enclosed in guard pipe, and exposed to an uncontrolled air environment.

Insert C

An inspection of the COND System piping that is below grade and enclosed in guard pipe will be performed within the 10-year period prior to entering the period of extended operation. Additional inspections of the COND System piping that is below grade and enclosed in guard pipe will be performed in each 10 year-period after entering the period of extended operation.

A.1.2.15 CRDRL Nozzle Program

The CRDRL Nozzle Program is an existing mitigation and condition monitoring program that manages cracking due to flaw growth of the control rod drive return line (CRDRL) nozzle, safe end, cap, and connecting welds. The CRDRL Nozzle Program consists of a) mitigation activities, and b) inspection, flaw evaluation, and repair in accordance with the ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWB, Table IWB 2500-1 (2001 Edition through 2003 Addenda) and the recommendations of NUREG-0619. System modifications were implemented by the original equipment manufacturer prior to initial startup to mitigate cracking. The BWR Water Chemistry Program monitors and controls reactor coolant water chemistry in accordance with BWRVIP guidelines to ensure the long-term integrity and safe operation of the critical regions of the CRDRL nozzle.

The CRDRL Nozzle Program credits portions of the Inservice Inspection (ISI) Program.

A.1.2.16 Diesel Starting Air Inspection

The Diesel Starting Air Inspection detects and characterizes the condition of materials for the DSA System air dryers and downstream piping and components (excluding the DSA System air receivers). The inspection provides direct evidence as to whether, and to what extent, a loss of material due to corrosion has occurred.

The Diesel Starting Air Inspection is a new one-time inspection that will be implemented prior to the period of extended operation. The inspection activities will be conducted within the 10-year period prior to the period of extended operation.

A.1.2.17 Diesel Systems Inspection

The Diesel Systems Inspection detects and characterizes the condition of materials for the interior of the exhaust piping for the Division 1, 2, and 3 diesels in the Diesel Engine Exhaust System, including the loop seal drains from the exhaust piping~~, and the drain pans and drain piping associated with air-handling units of the Diesel Building HVAC systems~~. The inspection provides direct evidence as to whether, and to what extent, a loss of material due to corrosion has occurred.

or cracking due to stress corrosion cracking

The Diesel Systems Inspection is a new one-time inspection that will be implemented prior to the period of extended operation. The inspection activities will be conducted within the 10-year period prior to the period of extended operation.

A.1.2.18 Diesel-Driven Fire Pumps Inspection

The Diesel-Driven Fire Pumps Inspection detects and characterizes the material condition of the interior of the Fire Protection System diesel engine exhaust piping, and of Fire Protection System diesel heat exchangers exposed to a raw water environment.

~~program provides for testing to identify the conditions of the conductor insulation, and also provides for periodic inspection and drainage (if necessary) of electrical manholes.~~

~~The Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program is a new aging management program that will be implemented prior to the period of extended operation. The frequency of the cable testing portion of the program will be once every 10 years, with the first test to be performed prior to the period of extended operation. The frequency of the manhole inspections will be at least once every two years, with the first inspections to be performed prior to the period of extended operation.~~

Insert A page A-18a

A.1.2.33 Inservice Inspection (ISI) Program

The Inservice Inspection (ISI) Program is an existing condition monitoring program that manages cracking due to SCC/IGA and flaw growth of multiple reactor coolant system pressure boundary components, including the reactor vessel, a limited number of internals components, and the reactor coolant system pressure boundary. The Inservice Inspection (ISI) Program also manages loss of material due to corrosion for reactor vessel internals components and reduction of fracture toughness due to thermal embrittlement of cast austenitic stainless steel pump casings and valve bodies.

The Inservice Inspection (ISI) Program details the requirements for the examination, testing, repair, and replacement of components specified in ASME Section XI for Class 1, 2, or 3 components. The Inservice Inspection (ISI) Program complies with the ASME Code requirements.

Replace with Insert A on Page A-19a.

The program scope has been augmented to include additional requirements, and components, beyond the ASME requirements. ~~Examples include the augmentation of ISI to expanded reactor vessel feedwater nozzle examinations, examinations of high energy line piping systems that penetrate containment, and examinations per Generic Letter 88-01.~~ Such augmentation is consistent with the ISI program description in NUREG-1801, Section XI.M1.

A.1.2.34 Inservice Inspection (ISI) Program – IWE

The Inservice Inspection (ISI) Program – IWE is an existing program that establishes responsibilities and requirements for conducting IWE inspections as required by 10 CFR 50.55a. The Inservice Inspection (ISI) Program – IWE includes visual examination of all accessible surface areas of the steel containment and its integral attachments, and containment pressure-retaining bolting in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWE.

The inservice examinations conducted throughout the service life of Columbia will comply with the requirements of the ASME Section XI Edition and Addenda

Insert A to Page A-19

Examples include the augmentation of ISI to expand reactor vessel feedwater nozzle examinations, examinations of high energy line piping systems that penetrate containment, examinations per Generic Letter 88-01, and examinations of shroud support plate access hole covers per BWRVIP guidance.

Table A-1
Columbia License Renewal Commitments

Item Number	Commitment	FSAR Supplement Location (LRA App. A)	Enhancement or Implementation Schedule
5) Buried Piping and Tanks Inspection Program	The Buried Piping and Tanks Inspection Program is an existing program that will be continued for the period of extended operation, with the following enhancements: • Revise the site program document to include the buried portions of the Radwaste Building Outside Air (WOA) piping. Add Insert A from page A-43a • Require that an inspection of a representative sample of buried piping be performed within the 10-year period prior to entering the period of extended operation (i.e., between year 30 and year 40). Add insert B from Page A-43a • Require an additional inspection of a representative sample of buried and below grade piping be performed within 10 years after entering the period of extended operation (i.e., between year 40 and year 50).	A.1.2.5	Enhancement prior to the period of extended operation. Then ongoing.
6) BWR Feedwater Nozzle Program	The BWR Feedwater Nozzle Program is an existing program that will be continued for the period of extended operation.	A.1.2.6	Ongoing
7) BWR Penetrations Program	The BWR Penetrations Program is an existing program that will be continued for the period of extended operation.	A.1.2.7	Ongoing
8) BWR Stress Corrosion Cracking Program	The BWR Stress Corrosion Cracking Program is an existing program that will be continued for the period of extended operation.	A.1.2.8	Ongoing

Insert A to LRA Table A-1 Item Number 5

- Revise the site program document to include cracking, loss of material and loss of pre-load of bolting as aging effects managed by the program.
- Revise the site program document to include loss of material of stainless steel piping and piping components as an aging effect managed by the program.

Insert B to LRA Table A-1 Item, Number 5

- Revise the site program document to include loss of material of COND System piping that is below grade and enclosed in guard pipe.

Insert A into page A-68a

Item Number	Commitment	FSAR Supplement Location (LRA App. A)	Enhancement or Implementation Schedule
62) Service Level 1 Protective Coatings Program	The Service Level 1 Protective Coatings Program is an existing program that will be continued for the period of extended operation.	A.1.2.55	Ongoing
63) Inservice Inspection (ISI) Program	Ultrasonic Testing (UT) examination of creviced shroud support plate access hole cover weld, top hat configuration, will be performed once a demonstrated acceptable UT technique becomes available.	A.1.2.33	When demonstrated acceptable UT technique is available. Then ongoing.

B.2.5 Buried Piping and Tanks Inspection Program

Program Description

~~The Buried Piping and Tanks Inspection Program will manage the effects of loss of material due to corrosion on the external surfaces of piping and tanks exposed to a buried environment.~~

Replace with Insert A on page B-39a

Insert C from page B-39a

The Buried Piping and Tanks Inspection Program is a combination of a mitigation program (consisting of protective coatings) and a condition monitoring program (consisting of visual inspections). Integrity of coatings will be inspected when components are excavated for maintenance or other reasons. If an opportunistic inspection has not occurred between year 30 and year 38, an excavation of a section of buried piping for the purpose of inspection will be performed before year 40. An additional inspection of buried piping will be performed within 10 years after entering the period of extended operation.

The Buried Piping and Tanks Inspection Program will continue to ensure that the pressure boundary integrity of the subject components is maintained consistent with the current licensing basis during the period of extended operation.

NUREG-1801 Consistency

The Buried Piping and Tanks Inspection Program is an existing Columbia program that, with enhancement, will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.M34, "Buried Piping and Tanks Inspection."

Exceptions to NUREG-1801

None.

Required Enhancements

Prior to the period of extended operation the enhancements listed below will be implemented in the identified program element:

- **Scope of Program –**

  Revise the site program document to include the buried portions of the Radwaste Building Outside Air (WOA) piping.

Add Insert B on page B-39a

Insert D from page B-39a

Insert A to LRA Section B.2.5, page B-39

The Buried Piping and Tanks Inspection Program will manage the effects of loss of material due to corrosion on the external surfaces of piping, piping components and tanks exposed to a buried environment. The program also manages cracking, loss of material and loss of pre-load for bolting exposed to a buried environment.

Insert B to LRA Section B.2.5, page B-39

Revise the site program document to include cracking, loss of material and loss of pre-load of bolting as aging effects managed by the program.

Revise the site program document to include loss of material of stainless steel piping and piping components as an aging effect managed by the program.

Insert C to LRA Section B.2.5, page B-39

The Buried Piping and Tanks Inspection Program will also manage the effects of loss of material due to corrosion on the external surfaces of the COND System piping that is below grade, enclosed in guard pipe, and exposed to an uncontrolled air environment.

Insert D to LRA Section B.2.5, page B-39

Revise the site program document to include loss of material of COND System piping that is below grade and enclosed in guard pipe.

- **Detection of Aging Effects –**

  Require that an inspection of a representative sample of buried piping be performed within the 10-year period prior to entering the period of extended operation (i.e., between year 30 and year 40).

  Require an additional inspection of a representative sample of buried piping be performed within 10 years after entering the period of extended operation (i.e., between year 40 and year 50).

Insert B from page B-40a

Operating Experience

No history of piping degradation due to external corrosion of buried piping was identified for Columbia through searches of operating experience or discussions with program owners. Columbia operating experience demonstrates that the coating of buried steel piping and tanks is effective in managing the effects of aging. Plant design considerations addressed the potential for degradation of buried piping components through the application of protective coatings.

A review was conducted of station piping failures, and it was determined that there had been no documented failures attributed to externally-initiated corrosion. Identified instances of leakage associated with buried piping have been the result of internal corrosion.

The environmental conditions at Columbia are very good based on the sandy soil and electrolyte resistivity of the soil which is considered very high. This has resulted in minimal degradation of buried piping as evidenced by excavations of certain sections of piping for examination. There have been no significant areas of degradation caused by protective coating failure. This was determined after a section of buried Standby Service Water (SW) System piping was excavated and evaluated in 2007.

Conclusion

Replace with Insert A on Page B-40a

~~The Buried Piping and Tanks Inspection Program will manage loss of material due to corrosion for susceptible piping components and tanks in buried environments.~~ The Buried Piping and Tanks Inspection Program, with the required enhancements, provides reasonable assurance that the aging effects will be managed such that components subject to aging management review will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

Insert C from page B-40a

Insert A to LRA Section B.2.5, page B-40

The Buried Piping and Tanks Inspection Program will manage cracking and loss of pre-load of bolting and loss of material due to corrosion for susceptible bolting, piping, piping components and tanks in buried environments.

Insert B to LRA Section B.2.5, page B-40

Require that an inspection of the COND System piping that is below grade and enclosed in guard pipe be performed within the 10-year period prior to entering the period of extended operation (i.e., between year 30 and year 40).
Require additional inspections of the COND System piping that is below grade and enclosed in guard pipe be performed in each 10 year-period after entering the period of extended operation (i.e., one between year 40 and year 50, and one between year 50 and year 60).

Insert C to LRA Section B.2.5, page B-40

The Buried Piping and Tanks Inspection Program will also manage the effects of loss of material due to corrosion on the external surfaces of the COND System piping that is below grade, enclosed in guard pipe, and exposed to an uncontrolled air environment.

B.2.17 Diesel Systems Inspection

Program Description

components

The Diesel Systems Inspection is a new one-time inspection that will detect and characterize the material condition of the interior of the exhaust piping for the Division 1, 2, and 3 diesels in the Diesel Engine Exhaust System, including the loop seal drains from the exhaust piping~~, and the drain pans and drain piping associated with air-handling units of the Diesel Building HVAC systems~~. The inspection provides direct evidence as to whether, and to what extent, a loss of material due to corrosion has occurred or is likely to occur.

or cracking due to stress corrosion cracking

Implementation of the Diesel Systems Inspection will provide confirmation that the integrity of the subject components will be maintained consistent with the current licensing basis during the period of extended operation.

NUREG-1801 Consistency

The Diesel Systems Inspection is a new one-time inspection for Columbia that will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section XI.M32, "One-Time Inspection."

Exceptions to NUREG-1801

None.

Aging Management Program Elements

The results of an evaluation of each program element are provided below.

components

and stainless steel

- Scope of Program
  The scope of the Diesel Systems Inspection includes the steel exhaust piping exposed to an air-outdoor environment, and the loop seal drains from the exhaust piping that are exposed to a raw water environment, for the following diesel engines:

  - DG-ENG-1A1/1A2
  - DG-ENG-1B1/1B2
  - DG-ENG-1C
  - DSA-ENG-C/2C

  ~~Additionally the stainless steel drain pans and steel drain piping exposed to a raw water environment and associated with the following equipment are in the scope of the Diesel Systems Inspection:~~

- ~~DMA-AH 11, 12, 21, 22, 31, 32, and 51 (air-handling unit housings)~~

- Preventive Actions
  No actions are taken as part of the Diesel Systems Inspection to prevent aging effects or to mitigate aging degradation.

- Parameters Monitored or Inspected
  The parameters to be inspected by the Diesel Systems Inspection include wall thickness or visual evidence of internal surface degradation~~,~~ of the diesel exhaust piping components ~~and the drain pans and drain piping~~ as measures of loss of material and cracking. Inspections will be performed by qualified personnel using established NDE techniques (i.e., ultrasonic examination). Visual inspection of the internals for evidence of cracking, corrosion and corrosion products may be performed as opportunities for access arise.

- Detection of Aging Effects
  The Diesel Systems Inspection will use a combination of established volumetric and visual examination techniques (such as equivalent to VT-1 or VT-3) performed by qualified personnel on a representative sample of the subject components to identify evidence of loss of material or cracking.

  The sample population will be determined by engineering evaluation based on sound statistical sampling methodology, and, where practical, will be focused on the components most susceptible to aging, such as due to their time in service, the severity of conditions during normal plant operations, and design margins.

  The Diesel Systems Inspection will be conducted after the issuance of the renewed license and prior to the end of the current operating license, with sufficient time to implement programmatic oversight for the period of extended operation. The activities will be conducted no earlier than 10 years prior to the end of the current operating license, so that conditions are more representative of the conditions expected during the period of extended operation.

- Monitoring and Trending
  This one-time inspection activity is used to characterize conditions and to determine if, and to what extent, further actions may be required. The activity includes provisions for increasing the inspection sample size and locations if degradation is detected.

  The sample size will be determined by engineering evaluation of the materials of construction, the environment (i.e., service conditions), aging effects, and operating experience (e.g., time in-service, susceptible locations, lowest design margins). Inspection findings that do not meet the acceptance criteria will be evaluated using acceptance criteria

the Columbia corrective action process to determine the need for subsequent aging management activities and for further monitoring and trending of the results.

- Acceptance Criteria
  Indications or relevant conditions of degradation detected during the inspection will be compared to pre-determined, *acceptance criteria.* Inspection results will be compared against ~~minimum wall thickness~~ values established in accordance with design requirements or engineering evaluation. If the acceptance criteria are not met, then the indications and conditions will be evaluated under the corrective action program to determine whether they could result in a loss of component intended function during the period of extended operation.

- Corrective Actions
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Confirmation Process
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Administrative Controls
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Operating Experience
  mechanisms are
  The Diesel Systems Inspection is a new one-time inspection activity for which plant operating experience has not shown the occurrence of the aforementioned aging ~~effect~~ effects. The activity provides confirmation of conditions where degradation is not expected, has not evidenced as a problem, or where the aging ~~mechanism is~~ slow acting. The inspection provides for confirmation of material conditions near the period of extended operation. The elements comprising the inspection activity are to be consistent with industry practice.

  NUREG-1801 is based on industry operating experience through January 2005. Recent industry operating experience has been reviewed for applicability; none was identified. Future operating experience is captured through the normal operating experience review process, which will continue through the period of extended operation.

  A review of Columbia operating experience to date has found no indications of loss of material or cracking in the subject diesel system components. The site corrective action

B.2.33 Inservice Inspection (ISI) Program

Program Description

The Inservice Inspection (ISI) Program manages cracking due to SCC/IGA and flaw growth of reactor coolant system pressure boundary components made of nickel alloy, stainless steel (including cast austenitic stainless steel), and steel (including steel with stainless steel cladding), including the reactor vessel, a limited number of internals components, and the reactor coolant system pressure boundary. The Inservice Inspection (ISI) Program also manages loss of material due to corrosion for reactor vessel internals components and reduction of fracture toughness due to thermal embrittlement of cast austenitic stainless steel pump casings and valve bodies.

The Columbia Inservice Inspection (ISI) Program meets the requirements of ASME Section XI. The Columbia Inservice Inspection (ISI) Program details the requirements for the examination, testing, repair, and replacement of components specified in ASME Section XI for Class 1, 2, or 3 components. The Columbia Inservice Inspection (ISI) Program complies with the ASME Code requirements, and is therefore consistent with the NUREG-1801 program. The program is described in FSAR Section 5.2.4 and is implemented by various plant procedures.

Replace with Insert A from Page B-136a

The Columbia program scope has been augmented to include additional requirements, and components, beyond the ASME requirements. ~~Examples include the augmentation of ISI to expanded reactor vessel feedwater nozzle examinations, examinations of high energy line piping systems that penetrate containment, and examinations per Generic Letter 88-01.~~ Such augmentation is consistent with the ISI program description in NUREG-1801, Section XI.M1.

The Columbia Inservice Inspection (ISI) Program contains a Risk-Informed Inservice Inspection (RI-ISI) program for Class 1 piping, based on EPRI Topical Report TR-112657 Revision B-A, which has been approved by the NRC staff. The RI-ISI provides alternate inspection requirements for a subset of Class 1 piping welds. The staff's review of the RI-ISI program for the third ISI 10-year interval concluded that the program is an acceptable alternative to the current ISI program based on the American Society of Mechanical Engineers Boiler and Pressure Vessel Code, Section XI requirements for Class 1, non-socket Category B-J welds. While this varies from the ASME Code, it represents a modernization of the Code that has been accepted by the NRC for use at many nuclear power plants, including Columbia. Because of the widespread NRC acceptance of Risk-Informed ISI, this is not considered an exception to NUREG-1801.

Evaluation of flaws in accordance with established site procedures using ASME Code and BWRVIP requirements may result in re-inspection or sample expansion.

Insert A to Page B-136

Examples include the augmentation of ISI to expand reactor vessel feedwater nozzle examinations, examinations of high energy line piping systems that penetrate containment, examinations per Generic Letter 88-01, and examinations of shroud support plate access hole covers per BWRVIP guidance.