

WOLF CREEK NUCLEAR OPERATING CORPORATION

Terry J. Garrett
Vice President, Engineering

May 25, 2007

ET 07-0020

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555

- Reference:
- 1) Letter ET 06-0038, dated September 27, 2006, from T. J. Garrett, WCNOG, to USNRC
 - 2) Letter ET 07-0011, dated May 2, 2007, from T. J. Garrett, WCNOG, to USNRC
 - 3) Letter ET 07-0016, dated May 10, 2007, from T. J. Garrett, WCNOG, to USNRC

Subject: Docket No. 50-482: Response to NRC Requests for Additional Information Related to Wolf Creek Generating Station License Renewal Application

Gentlemen:

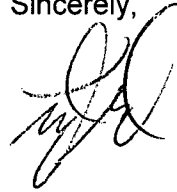
Reference 1 provided Wolf Creek Nuclear Operating Corporation's (WCNOG) License Renewal Application (LRA) for the Wolf Creek Generating Station (WCGS). As part of the review for license renewal, the Nuclear Regulatory Commission (NRC) staff conducted two audits at WCGS. The LRA Aging Management Programs audit was performed during the week of March 26, 2007 and the Aging Management Reviews during the week of May 7, 2007.

Enclosure 1 provides the question and answer database that was compiled during the audits. Each entry consists of a numbered question, reference to the applicable section of the LRA and the WCNOG response.

Attachment I provides a comprehensive commitment list including all commitments made in response to References 1, 2, and 3. Six commitments made in Reference 1, numbers 3, 6, 15, 17 and 26, have been revised. Commitment number 22 has been deleted. Two additional commitments have been added.

If you have any questions concerning this matter, please contact me at (620) 364-4084, or Mr. Kevin Moles at (620) 364-4126.

Sincerely,

A handwritten signature in black ink, appearing to read "TJG", written in a cursive style.

Terry J. Garrett

TJG/rtt


Attachment

Enclosure

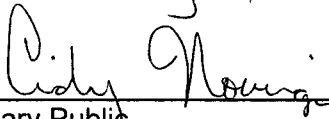
cc: J. N. Donohew (NRC), w/a, w/e
V. G. Gaddy (NRC), w/a, w/e
B. S. Mallett (NRC), w/a, w/e
V. Rodriguez (NRC), w/a, w/e
Senior Resident Inspector (NRC), w/a, w/e

STATE OF KANSAS)
) SS
COUNTY OF COFFEY)

Terry J. Garrett, of lawful age, being first duly sworn upon oath says that he is Vice President Engineering of Wolf Creek Nuclear Operating Corporation; that he has read the foregoing document and knows the contents thereof; that he has executed the same for and on behalf of said Corporation with full power and authority to do so; and that the facts therein stated are true and correct to the best of his knowledge, information and belief.

By 
Terry J. Garrett
Vice President Engineering

SUBSCRIBED and sworn to before me this 25th day of May, 2007.


Notary Public



Expiration Date 7/8/10

Wolf Creek AMP Audit Questions and Responses
Wolf Creek AMR Audit Questions and Responses
(114 Pages)

Wolf Creek AMP Audit Questions and Responses

Question No	LRA Sec	Audit Question	Final Response
AMPA001	B.2.1.22	What inspection techniques are to be utilized to detect degradations such as cracking, hardening, and loss of strength as stated in the description of this AMP in the License Renewal Application (LRA)?	<p>The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program uses visual inspection for detection of aging effects. Visual inspections of internal surfaces of plant components will be performed during the conduct of periodic maintenance, predictive maintenance, surveillance testing and corrective maintenance. Inspections will determine if cracking, loss of strength – hardening, or loss of material aging effects are occurring. Stainless steel exposed to diesel exhaust will be inspected for cracking. Other stainless steel components in the scope of the Internal Inspection program do not meet the 140° F threshold temperature for cracking. HVAC flexible connectors will be inspected to ensure they are free from hardening - loss of strength. Piping and piping components will be inspected for loss of material. Loss of strength - Hardening is only applicable to Elastomers in the HVAC systems. Physical manipulation during visual inspection of elastomers could be used to verify the absence of hardening or loss of strength. The AMP will provide procedural guidance and training required for personnel performing visual inspections.</p>
AMPA002	B.2.1.22	It is observed that WCGS has credited the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program for inspection of internal surfaces of steel, brass and aluminum piping, ducting and components. What is the minimum size of the piping and ducting covered under this AMP? Are there any special techniques planned to be used to detect corrosion of the nonferrous materials?	<p>The program plan procedure will specify what, if any exclusions will exist for small bore piping and ducting covered by the AMP. The program plan procedure has not been completed, however, currently there is no preset minimum piping or ducting size excluded from the program. Specific exclusions will depend upon many factors including constraints associated with inspection equipment (e.g. borescope size). All piping and ductwork currently in the scope of the program is identified, (see AMP applicability list). Piping currently in scope for the program is as small as ¼" though most of the piping is 1" or greater. Ducting currently in scope for the program ranges in size from 10" to 45" and only includes carbon steel (non-galvanized) ductwork. Visual Inspection is used exclusively for detection of aging effects in ferrous and non-ferrous materials. Visual inspection techniques utilized are the same regardless of whether the material is ferrous or non-ferrous, though industry experience will be utilized whenever possible to enhance detection of corrosion for nonferrous materials.</p>
AMPA003	B.2.1.6	The flow accelerated corrosion program described in the GALL Report relies on EPRI guidelines provided in NSAC 202L, Revision 2. WCGS's Flow Accelerated Corrosion Program is based on NSAC 202L, Revision 3. Provide justifications as	<p>As indicated in NSAC 202L, Revision 3, the new revision of EPRI guidelines incorporates lessons learned and improvements to detection, modeling, and mitigation technologies that became available since Revision 2 was published. The updated recommendations are intended to refine and enhance those of previous revisions without contradictions to ensure continuity of existing plant FAC programs.</p>

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		to how the Revision 3 guidelines are either equivalent or more stringent than those in Revision 2.	<p>The WCGS FAC program takes exception to the following NUREG-1801 XI.M17 program elements based on using guidance of NSAC 202L, Revision 3 instead of Revision 2. The sections of NSAC 202L associated with these program elements were reviewed to show that Revision 3 guidelines are equivalent to those in Revision 2:</p> <p>Element (1), Scoping of Program – The differences of section 4.2, Identifying Susceptible Systems, between Revision 2 and Revision 3 are mostly editorial. The guidance of prioritizing the system for evaluation in section 4.2.3 of Revision 2 is addressed in section 4.9 of Revision 3 by applying safety factors in ranking the risks. Section 4.4, Selecting and Scheduling Components for Inspection, of Revision 2 was re-organized in Revision 3. Sample selection for modeled lines and non-modeled lines of Revision 2 was enhanced with more clarification and more details in Revision 3, Guidance for using plant experience and industry experience in selecting inspection locations were added in Revision 3. The basis for sample expansion was clarified in Revision 3.</p> <p>Instead of dividing into selection of initial inspection and follow-up inspections in Revision 2, the guidance in Revision 3 is provided for a given outage including the recommendations for locations of re-inspection. It is more compatible to the schedule of the implementation of FAC program of the industry.</p> <p>Element (4), Detection of Aging Effects – Clarification of the inspection techniques of UT and RT was added in section 4.5.1 of Revision 3. There are no changes of the guidance for UT grid. Appendix B was added in Revision 3 to provide guidance for inspection of vessels and tanks. The guidance for inspection of small-bore piping in Appendix A of Revision 2 and 3 are essentially identical. The guidance for inspection of valves, orifices, and equipment nozzles were enhanced in section 4.5.2 of Revision 3. Also, section 4.5.4 was added for use of RT to inspect large-bore piping, section 4.5.5 for inspection of turbine cross-around piping, and section 4.5.6 for inspection of valves.</p>
AMPA004	B.2.1.6	Describe situations which demonstrate effectiveness of the Flow Accelerated Corrosion Program at WCGS. Include actual data (i.e., measured wall thickness, nominal pipe thickness, minimum acceptable thickness, etc.) and details of the corrective actions taken when	<p>Wolf Creek uses the guidance provided in EPRI NSAC 202L, "Recommendations for an Effective Flow-Accelerated Corrosion Program", which is utilized throughout the industry. This document has proven to provide input to effective programs. In addition, the components that are replaced in the Wolf Creek FAC program are normally replaced with FAC-resistant material; no failures have been identified with the FAC-resistant material.</p> <p>In August 1999, the Callaway pipe break occurred. Using our program,</p>

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		<p>degradation or wall thinning was observed during flow accelerated corrosion inspections. Describe how effective were these corrective actions in eliminating or controlling the wall thinning problem.</p>	<p>within the same month we inspected the identical location at Wolf Creek. Wall thinning was identified; the affected piping was replaced like-for-like two days later. Additional inspections were added to the next refueling outage (RF 11) inspection scope as a result of finding wall thinning. The entire pipeline was replaced with chrome-moly pipe in RF12. Re-inspection of replaced chrome-moly pipe is scheduled. (Ref PIRs 1999-2958, 2000-2032)</p> <p>Review of the work orders from 1995 showed that there has been no reported FAC-related leak or rupture at WCGS. Most of the work orders identified the degradation of wall thinning during the inspection by the FAC program. There was no case where the wall thickness was found to violate the minimum acceptable thickness. There were cases where the initial acceptable thickness determined in accordance with the program guidelines (Reference: AI 23H-002) were reached and more rigorous analyses were performed to justify continued service. Problems identified during implementation of the program activities were not significant and adequate corrective actions were taken to prevent recurrence.</p> <p>For previous refueling outages RF13 and RF14, 75 to 80 locations of large-bore systems were selected for inspection, including 25-30 locations of initial inspection. An inspection location included the subject component (such as an elbow) and its adjacent area (such as upstream and downstream piping). For small-bore systems, 40 to 50 inspections were selected for previous outages, including 20-30 locations of initial inspection. The replacements for each outage are scheduled on proactive basis, determined by the projected remaining service life based on FAC analyses and by programmatic strategy based on industry experience and cost comparison to further inspections. The selection of FAC-resistance material is chrome-moly alloy P22 (2.25% Cr and 1.00% Mo) for most of the replacements.</p>
AMPA005	B.2.1.6	<p>Clarify if there have been any modifications and/or improvements to the Flow Accelerated Corrosion Program since its implementation. Describe the specific reasons (i.e., lessons learned, operating experience, industry experience) for these modifications and/or improvements. Explain how these changes made the program more effective with respect to the</p>	<p>The improvements of the FAC program since its implementation are:</p> <ul style="list-style-type: none"> i. EPRI CHECWORKS software has been improved to better predict wear. ii. FAC Manager software was purchased about 3-4 years ago and is used to monitor (track, trend, and manage) inspection information. iii. NSAC 202L has been issued to provide program guidelines to the industry to provide consistent effectiveness. iv. WCGS has increased participation in EPRI CHUG (CHECWORKS Users Group) to better review and respond to issues within the industry.

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AMPA006	B.2.1.6	<p>management of aging.</p> <p>Explain how would the sample size be adjusted to address the detected degradation if the thickness measurements during flow accelerated corrosion inspection indicated degradation or wall thinning beyond the predicted minimum wall thickness. Actual wall thickness data collected during flow accelerated corrosion inspections should be available for review during audit.</p>	<p>The guidance for expanded sample inspection is provided in the procedure AI 23H-002, Rev. 2, Section 6.5.8. The expanded sample should include, if not recently inspected,</p> <ol style="list-style-type: none"> (1) any component within two pipe diameters downstream or within two pipe diameters upstream if the subject component is an expander or expanding elbow, (2) the two highest ranked components from the CHECWORK wear rate prediction from the train containing the piping component displaying the significant wear, and (3) Corresponding components of similar geometry in sister train displaying significant wear. <p>If inspection of the expanded sample detects additional components with significant FAC wear, the sample should be further expanded to include components of the aforementioned items (1) and (2). If additional significant wear is detected, the sample expansion should continue per above until no additional components with significant wear are detected.</p> <p>Summaries of FAC Inspection Results for the following refueling outages are provided in Section 2 of Program Evaluation Report (PER) for AMP B2.1.6, FAC Program:</p> <ol style="list-style-type: none"> (1) RF10 - WCNOG-126 (2) RF11 - WCNOG-147 (3) RF12 - WCNOG-152 (4) RF13 - WCNOG-155
AMPA007	B.2.1.6	<p>WCGS document AI 23H 002, Revision 2, Page 34, "Guidelines for Implementation of the Flow Accelerated Corrosion Program," includes a flow diagram for the evaluation process. The diagram shows that if "Tmeas" is not greater than "Tminacc", there are two logic steps to follow which state "Generate WR to document nonconformance". Please explain the purpose of these two steps and the difference between the two of them.</p>	<p>The two logic steps are duplicate and identical actions. The second logic box is not needed.</p>
AMPA008	B.2.1.6	<p>PIR No. 20002032 states: "After a</p>	<p>(a) Evaluation of the model was performed to determine why the</p>

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		<p>detailed review of the CHECWORKS model predicted wear rates and estimating the as measured wear rates, significant discrepancies in the predicted vs measured wear rate results were identified." In similar PIR documents that predicted wear rates the actual wear was estimated at:</p> <p>- 77% higher for the elbow on line AF 417 GBD 6 -263% higher for the elbow on line AF 032 GBD 6</p> <p>(a) Explain if the Flow Accelerated corrosion Program management team performed evaluation and root cause analyses to establish why the CHECWORKS predicted wear rates were different from the actual wear rates from the two cases quoted.</p> <p>(b) Explain if the modeling verified that similar problems did not exist at other locations. Explain what corrective actions were taken to assure that the future predictions were realistic and consistent with the actual wear.</p>	<p>CHECWORKS predicted wear rates were different from the actual wear rate. The possible cause could be due to backing rings installed during construction. Other locations were reviewed to verify consistency of the CHECWORKS results with the field-measured data, with no apparent deficiencies in the model identified.</p> <p>(b) An EPRI person was brought on site to review the FAC model in August-September of 1999. The objective of the review was to recommend additional inspection locations and to look for improvements to CHECWORKS FAC model. There were no major findings with the model that affect the predicted wear during the review. In 2006, Wolf Creek contracted CSI Technologies to upgrade to CHECWORKS version SFA 2.1 program, at that time the model was reviewed. At that same time the system susceptibility evaluation and susceptible non-modeled components were revised.</p>
AMPA009	B.2.1.6	<p>PIR No. 1999 2958 documents that radiography inspections were performed on high pressure feed water piping as a result of a pipe break at another nuclear power plant. The PIR states: "Wall thickness measurements at the location were estimated between 0.100 to 0.120 inches (Nominal of 0.280 in.). The critical wall thickness based on hoop stresses had been calculated at 0.109 inch. The</p>	<p>(a) Critical wall thickness is not a standard term used. "Tmin acceptable" is the design minimum acceptable wall thickness of the component. The method for determining the design minimum acceptable wall thickness of components inspected for wall thinning in the FAC Program shall be consistent with the ANSI B31.1, ASME Section III or VIII as applicable, Engineering Design Guides and Calculation procedure. Refer to AI 23H-002 Section 6.6.</p> <p>(b) The line that failed was within the scope of the FAC program, but the subject location was not ranked to be inspected. Other components within that line were inspected prior to the failure.</p>

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		<p>identified piping was replaced."</p> <p>(a) Explain what is the definition of critical wall thickness in the Flow Accelerated Corrosion Program. The estimated thickness value of 0.100 inch is less than the calculated critical thickness reported in the PIR. Explain what is the significance of critical thickness in the implementation of this program.</p> <p>(b) Clarify if the subject piping was part of the Flow Accelerated Corrosion Program or if the radiography was performed because of the failure of similar piping at the other nuclear plant.</p> <p>(c) Clarify if the affected piping was replaced with piping made from the same material or with a corrosion resistant material. The PIR talks about wall thinning at the extrados of the 45 degree elbow. Clarify if this fitting was also replaced.</p> <p>(d) Clarify how long was this piping in operation before the thickness loss was detected. Clarify if this piping was inspected earlier; if yes, show the dates and the inspection result. Explain what were the results of the engineering evaluations as referenced in the PIR and the corrective actions taken.</p>	<p>[c] The components with low thickness readings, including the 45-degree elbow, were replaced with like-for-like immediately (1999). During RF12 (2002) the line was replaced with chrome-moly pipe.</p> <p>(d) This piping was installed as part of the original construction and was placed in service in 1984. Selected piping segments downstream of the control valve and the first elbow were inspected in RF4 – results were acceptable.</p> <p>In addition to the examination of the location equivalent to Callaway's rupture location, piping components potentially susceptible to similar type of degradation contributing to the Callaway failure were selected for additional inspections to detect any unexpected pipe wall thinning. EPRI/WCGS joint effort evaluations were performed to identify the areas for improvements to the CHECWORKS FAC prediction model.</p> <p>The detail review of the CHECWORKS model was performed per PIR 2000-2032. The results of the review are summarized in the response to AMP Audit Question #AMPA008 (#B.2.1.6-6). No apparent deficiencies in the model were identified.</p> <p>The results of the inspections for additional locations and the recommended corrective actions are provided in PIR 2000-2032. All subsequent inspections and/or replacements in the affected components are tracked/trended and implemented under the WCGS FAC program. The piping associated with the Callaway rupture has been replaced with FAC resistant material.</p>
AMPA010	B.2.1.30	The operating experience described in LRA Section B.2.1.30, states that "One gasket degradation has been noted. The gasket was installed in 1989, exhibited an increasing leakage trend since 1993 and was	The gasket being discussed is for equipment hatch ZX01. The gasket material is an elastomer known as EPDM (Ethylene Propylene Diene Monomer rubber). The manufacturer is Presray Corporation. EPDM grade E-603 (ref: Work Package 111933, Bill of Materials). The original and replacement gaskets were made of the same material. The ZX01 equipment hatch is tested every refueling outage. The leakage

Question No	LRA Sec	Audit Question	Final Response																																								
		<p>replaced in 1997.”</p> <p>Clarify which gasket is being discussed and what was the gasket material. Clarify if the replacement gasket was of the same material. Clarify how frequently has the gasket been inspected after its replacement and show the inspection results.</p>	<p>acceptance criteria for the equipment hatch seal is 4,200 sccm. LLRT data for equipment hatch ZX01 from 10/04/1997 failure date to present:</p> <table border="1"> <thead> <tr> <th>LLRT Date</th> <th>Component</th> <th>Leakage(sccm)</th> <th>Error(sccm)</th> </tr> </thead> <tbody> <tr> <td>11/6/2006</td> <td>ZX-01</td> <td>20</td> <td>3.7</td> </tr> <tr> <td>5/11/2005</td> <td>ZX-01</td> <td>120</td> <td>20</td> </tr> <tr> <td>11/27/2003</td> <td>ZX-01</td> <td>0</td> <td>4</td> </tr> <tr> <td>04/23/2002</td> <td>ZX-01</td> <td>170</td> <td>20</td> </tr> <tr> <td>10/27/2000</td> <td>ZX-01</td> <td>0</td> <td>4</td> </tr> <tr> <td>05/03/1999</td> <td>ZX-01</td> <td>40</td> <td>3.7</td> </tr> <tr> <td>04/03/1999</td> <td>ZX-01</td> <td>20</td> <td>3.7</td> </tr> <tr> <td>11/20/1997</td> <td>ZX-01</td> <td>20</td> <td>3.88</td> </tr> <tr> <td>10/04/1997</td> <td>ZX-01</td> <td>6200</td> <td>230</td> </tr> </tbody> </table>	LLRT Date	Component	Leakage(sccm)	Error(sccm)	11/6/2006	ZX-01	20	3.7	5/11/2005	ZX-01	120	20	11/27/2003	ZX-01	0	4	04/23/2002	ZX-01	170	20	10/27/2000	ZX-01	0	4	05/03/1999	ZX-01	40	3.7	04/03/1999	ZX-01	20	3.7	11/20/1997	ZX-01	20	3.88	10/04/1997	ZX-01	6200	230
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AMPA011	B.2.1.30	<p>Explain if the containment leakage test program require a local leak rate testing after the maintenance work or repair activities are performed on the containment boundary components (i.e., isolation valves, penetration seals, gaskets etc.) Explain how are the “as found” leakage rates applied if they exceeded the administrative leakage limits.</p>	<p>Type B & C as-found testing is performed prior to any repair, modification, or adjustment activity, if the activity would affect the penetration/valve leak tightness.</p> <p>Type B & C as-left testing is performed after any repair, modification, or adjustment activity, if the activity would affect the penetration/valve leak tightness.</p> <p>The as-found leakage rates, determined on a minimum pathway leakage rate basis, for all newly tested penetrations/valves is summed with the as-left minimum pathway leakage rate for all other penetrations and valves subject to Type B and C tests to calculate the overall Type B & C leakage rate. For Type B or C tests that are not acceptable, the testing frequency shall be set to the initial test frequency (30 months or less). A cause determination in accordance with AP 28A-001, Performance Improvement Request shall be performed and corrective actions identified to eliminate the identified failure cause and prevent recurrence.</p> <p>For the purpose of the Inservice Testing Program, which utilizes the Containment Leakage Rate Testing Program to satisfy category A isolation valve leakage test, a maximum allowable leakage rate of 10,000 sccm or the administrative limit, whichever is larger is specified for any single component/penetration. If this maximum allowable leakage rate is exceeded, repair or replacement shall be initiated in accordance with AP 16C-005, MPAC Work Request.</p> <p>(ref. AP 29E-001, Program Plan for Containment Leakage Measurement, Section 6.2, 6.7.2, 6.8.4 & 6.8.6)</p>																																								
AMPA012	B.2.1.30	Clarify what are the test intervals for	Type A test interval frequency is every ten years. If Type A test																																								

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		<p>Type A, B and C tests for the leak rate test program. Explain how is the test interval for the Type A test adjusted if the leakage rate testing yields unacceptable results.</p>	<p>performance is unacceptable, the cause will be identified and corrective actions taken to restore satisfactory performance. A subsequent Type A test must be performed within 48 months following the unsuccessful test. If the subsequent test is successful, the frequency may be returned to 10 years. (ref: WCGS-AMP-B2.1.30, Section 3.5 and 3.7)</p> <p>Type B & C are conducted at various intervals for the many different penetrations depending upon various factors for individual containment isolation components. These factors include past component performance, maintenance history, service environment, design and safety significance. For penetrations that demonstrate acceptable performance, the Type B test interval can be extended to a maximum of 120 months. For containment isolation valves that demonstrate acceptable performance, the Type C test interval can be extended to a maximum of 60 months. Containment purge and vent valves are tested at a periodicity of not greater than 3 months. Current Type B & C test frequencies are shown below:</p> <table border="1" data-bbox="1024 718 1908 1488"> <thead> <tr> <th data-bbox="1024 718 1465 751">Description</th> <th data-bbox="1465 718 1759 751">Component</th> <th data-bbox="1759 718 1908 751">Frequency</th> </tr> </thead> <tbody> <tr> <td>Personnel Air Lock (barrel)</td> <td>ZX-003,L003</td> <td>RF</td> </tr> <tr> <td>Emergency Air Lock(barrel)</td> <td>ZX-002,L001</td> <td>RF</td> </tr> <tr> <td>Emergency Air Lock (door seal)</td> <td>ZX-02</td> <td>RF</td> </tr> <tr> <td>Equipment Hatch</td> <td>ZX-001,L002</td> <td>RF</td> </tr> <tr> <td>Ctmt Recirc Sump/RHR B Sample</td> <td>EJHV0024</td> <td>3RF</td> </tr> <tr> <td>Ctmt Recirc Sump/RHR B Sample</td> <td>EJHV0026</td> <td>3RF</td> </tr> <tr> <td>Ctmt Recirc Sump/RHR A Sample</td> <td>EJHV0023</td> <td>3RF</td> </tr> <tr> <td>Ctmt Recirc Sump/RHR A Sample</td> <td>EJHV0025</td> <td>3RF</td> </tr> <tr> <td>Fuel Transfer Tube</td> <td>Flange</td> <td>RF</td> </tr> <tr> <td>Loop B Seal Water Injection</td> <td>BBHV8351B</td> <td>3RF</td> </tr> <tr> <td>Loop B Seal Water Injection</td> <td>BBV0148</td> <td>3RF</td> </tr> <tr> <td>CVCS Letdown</td> <td>BGHV8152</td> <td>3RF</td> </tr> <tr> <td>CVCS Letdown</td> <td>BGHV8160</td> <td>3RF</td> </tr> <tr> <td>Seal Water Return</td> <td>BGHV8100</td> <td>3RF</td> </tr> <tr> <td>Seal Water Return</td> <td>BGHV8112</td> <td>3RF</td> </tr> <tr> <td>Seal Water Return</td> <td>BGV0135</td> <td>3RF</td> </tr> <tr> <td>RX Makeup Water</td> <td>BL8046</td> <td>3RF</td> </tr> <tr> <td>RX Makeup Water</td> <td>BLHV8047</td> <td>3RF</td> </tr> <tr> <td>RX Coolant Drain TK Discharge</td> <td>HBHV7136</td> <td>3RF</td> </tr> <tr> <td>RX Coolant Drain TK Discharge</td> <td>HBHV7176</td> <td>3RF</td> </tr> <tr> <td>ESW To B & D Ctmt Coolers</td> <td>EFHV0032/EFHV0034</td> <td>2RF</td> </tr> <tr> <td>ESW From B & D Ctmt Coolers</td> <td>EFHV0046/EFHV0050</td> <td>RF -</td> </tr> <tr> <td>Change after RF17</td> <td></td> <td></td> </tr> </tbody> </table>	Description	Component	Frequency	Personnel Air Lock (barrel)	ZX-003,L003	RF	Emergency Air Lock(barrel)	ZX-002,L001	RF	Emergency Air Lock (door seal)	ZX-02	RF	Equipment Hatch	ZX-001,L002	RF	Ctmt Recirc Sump/RHR B Sample	EJHV0024	3RF	Ctmt Recirc Sump/RHR B Sample	EJHV0026	3RF	Ctmt Recirc Sump/RHR A Sample	EJHV0023	3RF	Ctmt Recirc Sump/RHR A Sample	EJHV0025	3RF	Fuel Transfer Tube	Flange	RF	Loop B Seal Water Injection	BBHV8351B	3RF	Loop B Seal Water Injection	BBV0148	3RF	CVCS Letdown	BGHV8152	3RF	CVCS Letdown	BGHV8160	3RF	Seal Water Return	BGHV8100	3RF	Seal Water Return	BGHV8112	3RF	Seal Water Return	BGV0135	3RF	RX Makeup Water	BL8046	3RF	RX Makeup Water	BLHV8047	3RF	RX Coolant Drain TK Discharge	HBHV7136	3RF	RX Coolant Drain TK Discharge	HBHV7176	3RF	ESW To B & D Ctmt Coolers	EFHV0032/EFHV0034	2RF	ESW From B & D Ctmt Coolers	EFHV0046/EFHV0050	RF -	Change after RF17		
Description	Component	Frequency																																																																									
Personnel Air Lock (barrel)	ZX-003,L003	RF																																																																									
Emergency Air Lock(barrel)	ZX-002,L001	RF																																																																									
Emergency Air Lock (door seal)	ZX-02	RF																																																																									
Equipment Hatch	ZX-001,L002	RF																																																																									
Ctmt Recirc Sump/RHR B Sample	EJHV0024	3RF																																																																									
Ctmt Recirc Sump/RHR B Sample	EJHV0026	3RF																																																																									
Ctmt Recirc Sump/RHR A Sample	EJHV0023	3RF																																																																									
Ctmt Recirc Sump/RHR A Sample	EJHV0025	3RF																																																																									
Fuel Transfer Tube	Flange	RF																																																																									
Loop B Seal Water Injection	BBHV8351B	3RF																																																																									
Loop B Seal Water Injection	BBV0148	3RF																																																																									
CVCS Letdown	BGHV8152	3RF																																																																									
CVCS Letdown	BGHV8160	3RF																																																																									
Seal Water Return	BGHV8100	3RF																																																																									
Seal Water Return	BGHV8112	3RF																																																																									
Seal Water Return	BGV0135	3RF																																																																									
RX Makeup Water	BL8046	3RF																																																																									
RX Makeup Water	BLHV8047	3RF																																																																									
RX Coolant Drain TK Discharge	HBHV7136	3RF																																																																									
RX Coolant Drain TK Discharge	HBHV7176	3RF																																																																									
ESW To B & D Ctmt Coolers	EFHV0032/EFHV0034	2RF																																																																									
ESW From B & D Ctmt Coolers	EFHV0046/EFHV0050	RF -																																																																									
Change after RF17																																																																											

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		Instrument Air	KAFV0029 3RF
		Instrument Air	KAV0218 3RF
		Instrument Air	KAV0204 3RF
		Ctmt Sump Discharge	LFFV0095 3RF
		Ctmt Sump Discharge	LFFV0096 3RF
		ILRT Pressurization Line	Flange 6RF
		ISI Penetration	Flange 6RF
		Loop C Seal Water Injection	BBHV8351C 3RF
		Loop C Seal Water Injection	BBV0178 3RF
		Loop D Seal Water Injection	BBHV8351D 3RF
		Loop D Seal Water Injection	BBV0208 3RF
		Loop A Seal Water Injection	BBHV8351A 3RF
		Loop A Seal Water Injection	BBV0118 3RF
		Aux Steam Decon	HDV0016 3RF
		Aux Steam Decon	HDV0017 3RF
		RX Coolant Drain TK N2 Supply	HBHV7126 3RF
		RX Coolant Drain TK N2 Supply	HBHV7150 3RF
		Accumulator N2 Supply	EPHV8880 3RF
		Accumulator N2 Supply	EPV0046 3RF
		ILRT PS (003-HBB-1")	Flange 6 RF
		ILRT PS (005-HBB-1")	Flange 6 RF
		Fuel Pool Cooling/Cleanup Supply	ECV0083 3RF
		Fuel Pool Cooling/Cleanup Supply	ECV0084 3RF
		Fuel Pool Cooling/Cleanup Return	ECV0087 3RF
		Fuel Pool Cooling/Cleanup Return	ECV0088 3RF
		Fuel Pool Cooling/Cleanup Skimmer	ECV0095 3RF
		Fuel Pool Cooling/Cleanup Skimmer	ECV0096 3RF
		H2 Analyzer Return	GSHV0008 3RF
		H2 Analyzer Return	GSHV0009 3RF
		CTMT Atmosphere Monitor Return	GSHV0038 3RF
		CTMT Atmosphere Monitor Return	GSHV0039 3RF
		RX Drain TK Sample	SJHV0131/SJHV0132 3RF
		RX Drain TK Sample	SJV0111 3RF
		Accumulator Fill From SI	EMHV8888 3RF
		Accumulator Fill From SI	EMV0006 3RF
		Pressurizer Relief TK N2 Supply	BBHV8026 3RF
		Pressurizer Relief TK N2 Supply	BBHV8027 3RF
		Service Air Supply	KAV0039 2RF
		Service Air Supply	KAV0118 2RF
		Pressurizer Liquid Sample	SJHV0128 3RF
		Pressurizer Liquid Sample	SJHV0129/SJHV0130 3RF
		Hydrogen Purge	GSHV0020/GSHV0021 RF

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		Fire Protection	KCHV0253 RF
		Fire Protection	KCV0478 2RF
		ISI Penetration	Flange 6RF
		Pressurizer Liquid Sample	SJHV0012 3RF
		Pressurizer Liquid Sample	SJHV0013 3RF
		ESW To A & C Ctmt Coolers	EFHV0031/EFHV0033 3RF
		ESW From A & C Ctmt Coolers	EFHV0045/EFHV0049 2RF
		CCW Supply	EGHV0058/EGHV0127 3RF
		CCW Supply	EGV0204 3RF
		CCW Return	EGHV0059/EGHV0131 3RF
		CCW Return	EGHV0060/EGHV0130 3RF
		CCW TB Return	EGHV0061/EGHV0133 3RF
		CCW TB Return	EGHV0062/EGHV0132 3RF
		Steam Generator Drain	BMV0045 3RF
		Steam Generator Drain	BMV0046 3RF
		CVCS Charging	BG8381 3RF
		CVCS Charging	BGHV8105 3RF
		ECCS Test	EMHV8871 3RF
		ECCS Test	EMHV8964 3RF
		RX Coolant Loop A Hot Leg Sample	SJHV0005 3RF
		RX Coolant Loop A Hot Leg Sample	SJHV0006/SJHV0127 3RF
		Accumulator Liquid Sample	SJHV0018 RF
		Accumulator Liquid Sample	SJHV0019 3RF
		H2 Analyzer Return	GSHV0017 3RF
		H2 Analyzer Return	GSHV0018 3RF
		CTMT Atmosphere Monitor Return	GSHV0033 3RF
		CTMT Atmosphere Monitor Return	GSHV0034 3RF
		Breathing Air	KBV0001 3RF
		Breathing Air	KBV0002 3RF
		H2 Analyzer Sample	GSHV0003 3RF
		H2 Analyzer Sample	GSHV0004 3RF
		H2 Analyzer Sample	GSHV0005 3RF
		CTMT Atmosphere Monitor Sample	GSHV0036 3RF
		CTMT Atmosphere Monitor Sample	GSHV0037 3RF
		H2 Analyzer Sample	GSHV0012 3RF
		H2 Analyzer Sample	GSHV0013 3RF
		H2 Analyzer Sample	GSHV0014 3RF
		CTMT Atmosphere Monitor Sample	GSHV0031 3RF
		CTMT Atmosphere Monitor Sample	GSHV0032 3RF
		Fiber Optics	PEFO 6RF
		Shutdown Purge Exhaust	GTHZ0008 92 days
		Shutdown Purge Exhaust	GTHZ0009 92 days

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			Shutdown Purge Supply GTHZ0006 92 days Shutdown Purge Supply GTHZ0007 92 days Mini Purge Exhaust GTHZ0011 92 days Mini Purge Exhaust GTHZ0012 92 days Mini Purge Supply GTHZ0004 92 days Mini Purge Supply GTHZ0005 92 days South Electrical Penetrations PES 6RF North Electrical Penetrations PEN 6RF
AMPA013	B.2.1.20	External Surfaces Monitoring Program is credited for aging management of elastomer seals and flex connectors for hardening and loss of strength. The applicant referenced GALL AMP XI.M36 which is used to monitor external steel surfaces for loss of material and leakage by visual inspection. Since the elastomers can deteriorate and loose strength without showing a change in the visual appearance, clarify what inspection techniques are used in the External Surfaces Monitoring Program to detect hardening and loss of strength of elastomers.	Visual inspections are the primary program method for detecting external corrosion or material aging degradation, such as cracking of elastomers resulting from hardening or loss of strength. Physical manipulation during the visual inspection can also be used to verify the absence of hardening or loss of strength for elastomers. (Element 4)
AMPA014	B.2.1.20	The External Surfaces Monitoring Program is credited for aging management of tube sides of several heat exchangers (e.g., HX Nos. 131, 142, 145 and 148). Clarify what type of heat exchangers are these. Clarify if the tube bundles are exposed to the indoor air such that they are accessible for surface inspections.	<p>There are forty-two heat exchanger tube side components that credit External Surfaces Monitoring for aging management. Thirty-eight of those components are heat exchanger heads (e.g. Hx Nos 131, 142, 145, & 148) that are described as heat exchanger tube side components only because they contain the tube side fluid. The heat exchanger heads are exposed to plant indoor air externally. The other four components are containment cooler manifolds that are described as heat exchanger tube side components only because they contain the tube side fluid. The containment cooler manifolds are exposed to plant indoor air externally.</p> <p>The tube bundles related to these forty-two components are not exposed to plant indoor air and are not managed by the External Surfaces Monitoring Program.</p>
AMPA015	B.2.1.20	Clarify if there are any components covered by the External Surfaces Monitoring Program that are not accessible during both plant	There are no components that have been specifically identified as being inaccessible during both plant operations and refueling outages, however, the External Surfaces Monitoring Program has provisions for any such cases. (The External Surfaces Monitoring Program has not been credited

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		<p>operations and refueling outages. If yes, explain how the applicant will ensure proper inspection of these components. Also, discuss how the components covered by insulation are inspected under this AMP.</p>	<p>for any components that are either submerged or encased in concrete.) Components that are inaccessible during both plant operations and refueling outages are evaluated to ensure that they have been/will be inspected at frequencies that provide reasonable assurance that the effects of aging will be managed such that the applicable intended functions will be maintained during the period of extended operation. (Element 4).</p> <p>The program provides clarification for areas, or portions of systems or components, that are difficult to access or are exempted from walkdown inspections based on physical (insulated, shielded, etc.) or environmental constraints (radiation levels, etc.). Exempted areas, or exempted portions of systems or components are to be documented on the walkdown inspection checklist, and an evaluation performed to determine that prior to the next refueling cycle, there is reasonable assurance that the effects of aging are managed such that applicable components will perform their intended function (Element 1).</p>
AMPA016	B.2.1.20	<p>PIR No. 20032733 reports a condition where the essential service water supply piping to the motor driven auxiliary feedwater pump B had not been coated after its installation and external corrosion was evident on the welds, heat affected zones, and valve EF V362. Clarify if the corrosion observed was severe enough to warrant evaluation of wall thinning. Describe what corrective actions were taken to assure that similar problems were avoided in the future.</p>	<p>The corrosion was evaluated as minor surface rust. No additional evaluation was undertaken. The components were determined to have been on the maintenance backlog for the coating. The components were prepped and coated; no further corrective actions were taken.</p>
AMPA017	B.2.1.20	<p>The External Surfaces Monitoring Program operating experience discusses several work orders. The problem descriptions included in WO 01 224361 000, WO 01 226813 000, WO 95 107292 000, WO 98 129513 001, and WO 99 208339 000 are incomplete. Provide the complete problem descriptions for these work orders.</p>	<p>WO 01-224361-000 Pipe Flange bolts need to be checked and at least one replaced due to rust. It appears that the bolts are rusted due to leakage or condensation. The flange gasket is not leaking at this time. This was written up in 1997, WR#97-126320-002, but it has either rusted again since, or was not replaced at that time.</p> <p>WO 01-226813-000 A ESW outlet line EF-223-HBC-30 downstream of EFV108 near the wall penetration, the exterior coating has failed and surface rust is evident. The loose paint and exterior corrosion should be removed from the pipe</p>

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			<p>and QC should perform a visual examination prior to application of the coating. Note to QC: UT Activity number 03101 grid markings will be impacted by this activity.</p> <p>WO 95-107292-000 Screen requires refurbishment due to corrosion of steel parts. Removal of screen from well is needed. Reference eng dispo 04410-92, rev 0 and rev 1 by Sathi (11-10-95) fef01b</p> <p>WO 98-129513-00 1WS01PA, Service Water Pump "A" needs packing adjustment to minimize leakage. Water spill in the pump house is degrading the supports for the heat trace panel and cable due to the standing water. Leak off piping needs replacement. Fin Team - adjust the packing and make a new task to replace the piping and sent to Maintenance Shop.</p> <p>WO 99-208339-000 During the performance of STS MT-011 it was noted that the forward load pin and paddle on a PSA 1 snubber attached to hanger BM18-R513 has moderate to heavy rust build up. This should be cleaned so that it doesn't affect the spherical bearing. CWA notify Robin Rumas when the rust is removed so QC can complete STS MT-11.</p>
AMPA018.	B.2.1.4	Explain how the vessel head is inspected for evidence of boric acid.	<p>AMP B2.1.4 Element 4 states that "locating small leaks" is identified through walkdowns of systems containing reactor coolant or treated borated water, formalized inspections of reactor coolant and treated borated water systems, and reactor coolant system leak rate monitoring.</p> <p>AMP B2.1.4 Element 4 also identifies that reactor vessel head examinations are conducted as follows:</p> <p>(1) Reactor coolant pressure boundary integrity walkdowns are performed by Level II or Level III VT-2 certified personnel using the examination techniques of QCP-20-520, Pressure Test Examination. Attachment G of STN PE-040D documents reactor head inspection results. Any evidence that boron leakage from above vessel may have penetrated the mirror insulation SHALL require a head bare metal inspection for the potentially affected areas of the vessel head, and require cleanup of head and mirror insulation.</p> <p>(2) Additional inspections that are NRC commitments for RPV closure head inspections have been implemented per NRC Order EA-03-009. (See AMP B2.1.5, Nickel-Alloy Penetration Nozzles Welded to the Upper</p>

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			Vessel Closure Heads of PWRs). This includes bare metal visual examination of the head surface, performed every third refueling or five years, whichever occurs first. Attachment C of STN PE-40E documents reactor head examination results.
AMPA019	B.2.1.4	Clarify if there are plans to replace the vessel head.	Wolf Creek has initiated a project to purchase a reactor vessel head forging as a risk management tool against the increasing world demand for ultra heavy forgings. The decision to finish machining the forging and initiate a project to replace the existing reactor vessel head will be made at a later date.
AMPA020	B.2.1.4	<p>Discuss how the applicant responded to the NRC's orders and bulletins listed below. Explain how these responses have been used to update the component list locations and visual inspections within the scope of the Boric Acid Corrosion Program.</p> <ul style="list-style-type: none"> · NRC Bulletin 2002-01, dated March 29 and May 16, 2002 · NRC RAI on Bulletin 2002 01, dated January 17, 2003 · NRC Bulletin 2003-02, dated September 19, 2003 · NRC Order EA 03 009, dated March 3, April 11, and April 18, 2003 · NRC Bulletin 2004-01, dated May 28, 2004 	<p>Wolf Creek responses to the referenced NRC generic communications are contained in the letters referenced below. Copies of the Wolf Creek letters are available on site for review or in ADAMS.</p> <p>NRC Bulletin 2002-01 "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity"</p> <ol style="list-style-type: none"> 1. WCNO Letter ET 02-0018 dated April 03, 2002 Response to NRC Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity" 2. WCNO Letter ET 02-0021 dated May 16, 2002 60 day response to NRC Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity" 3. WCNO Letter ET 03-0007 dated January 31, 2003 Response to Request for Additional Information for NRC Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity" <p>NRC EA-03-009 "Issuance of First Revised Order (EA-03-0009) Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors"</p> <ol style="list-style-type: none"> 1. WCNO Letter WM 04-0001 dated January 22, 2004 60 Day Report for NRC Order EA-03-009, "Issuance of First Revised Order (EA-03-0009) Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors" 2. WCNO Letter WM 04-0004 dated March 04, 2004 Response to NRC Order, "Issuance of First Revised Order (EA-03-0009) Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors" 3. WCNO Letter WM 06-0051 dated December 20, 2006 60-Day Report for NRC Order EA-03-009, "Issuance of First Revised

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			<p>Order Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors"</p> <p>4. Note: additional letters relative to the Wolf Creek relaxation request are noted in the response to question A057</p> <p>NRC Bulletin 2003-02 "Leakage from Reactor Pressure Vessel Lower Head Penetrations and reactor Pressure Boundary Integrity"</p> <p>1. WCNO Letter WM 03-0044 dated September 19, 2003 Response to NRC Bulletin 2003-02, "Leakage from Reactor Pressure Vessel Lower Head Penetrations and reactor Pressure Boundary Integrity"</p> <p>2. WCNO Letter WM 04-0002 dated January 22, 2004 60 day Report to NRC Bulletin 2003-02, "Leakage from Reactor Pressure Vessel Lower Head Penetrations and reactor Pressure Boundary Integrity"</p> <p>3. NRC Letter 05-00051 dated January 20, 2005 Wolf Creek Generating Station - Response to NRC Bulletin 2003-02, "Leakage From Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity"</p> <p>NRC Bulletin 2004-01 "Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam Space Piping Connections at PWRs"</p> <p>1. WCNO Letter ET 05-0015 dated July 14, 2005 60 Day Report for NRC Bulletin 2004-01, "Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam Space Piping Connections at PWRs"</p> <p>2. WCNO Letter WO 04-0039 dated July 27, 2004 60 Day Response to NRC Bulletin 2004-01, "Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam Space Piping Connections at PWRs"</p> <p>Changes to the Wolf Creek Boric Acid Corrosion Control Program as a result of the referenced NRC Generic Communications:</p> <p>AP 16F-001 Boric Acid Corrosion Control Program Revision 2 was approved December 18, 2000 – no change Revision 3 was approved May 5, 2005 and was a major revision that included the changes noted below. Revision 4 was approved October 14, 2005 (current revision – no change) Revision 3 changes: 1. As part of this revision two additional AIs were prepared:</p>

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			<ul style="list-style-type: none"> - AI 16F-001 Evaluation of Boric Acid Leakage - AI 16F-002 Boric Acid Leakage Management <p>2. Section 6.0 was revised to identify the main elements (8) of the program and on a programmatic level, describe how the elements are to be fulfilled. Revisions also described ties to other processes and procedures which are integral to the ability of the BACC Program to meet the objectives of the program.</p> <p>3. Attachment A was added to provide guidance on leakage</p> <p>4. Attachment B was added to clarify/capture frequency of program inspections/examinations (references NRC Bulletin 2002-01 & NRC Order EA-03-009 inspections)</p> <p>STN PE-040D RCS Pressure Boundary Integrity Walkdown Revision 1 was approved July 17, 2001 – no change Revision 2 was approved May 22, 2003 is the current revision and includes the following changes:</p> <ul style="list-style-type: none"> 1. Added new sections to examine the vessel safe-end nozzles, vessel sides and bottom penetrations. 2. Added Attachment I for Reactor Vessel Loop Safe-Ends Inspection results and Attachment J for Reactor Vessel Sides and Bottom Head Inspection Results 3. Revised Attachment G, Containment - Reactor Cavity Inspection Results to note that any evidence of boron leakage from above vessel may have penetrated the mirror insulation shall require a head bare metal inspection of the potentially affected areas. 4. Attachment K added to identify components/locations containing Alloy 600 materials which have been shown to be susceptible to PWSCC.
AMPA021	B.2.1.7	Clarify if WCGS has bolting expert in accordance with EPRI recommendations.	EPRI TR-104213 December 1995, Bolted Joint Maintenance & Application Guide section 1.9 recommends providing an on-site bolting coordinator, empowered to implement a program to eliminate failures. EPRI TR-104213 identifies a bolting coordinator as an individual who has the technical ability and authority to focus on both programmatic issues and day-to-day resolution of problems. Wolf Creek mechanical design engineering provides the functions of the bolting coordinator consistent with guidance of EPRI TR-104213.
AMPA022	B.2.1.7	Clarify if WCGS has ever purchased counterfeit bolting. Clarify if WCGS has a procedure to identify counterfeit bolting. Explain what has WCGS done in response to NRC Information Notice No. 89 59, "Suppliers of Potentially	NRC Information Notice No. 89 59 and the supplements were reviewed for applicability under the WCGS Industry Technical Information Program (ITIP). It was concluded that WCGS did not have any fasteners supplied by the vendors listed in this Notice that had involvement in counterfeit bolts/fasteners. Procedure AP 24D-003, "Receipt Inspections", Attachment B, provides

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		Misrepresented Fasteners."	guidance to identify items that may be substandard, misrepresented, or supplied with fraudulent documentation. If an item exhibits such indications, it directs to procedure AP 24H-003, "Commodity Discrepancies", for further investigations and corrective actions.
AMPA023	B.2.1.7	Describe the maintenance procedures used to check bolt torque and the uniformity of gasket compression. Provide the frequency for the maintenance activity.	<p>In accordance with plant procedures on bolting installations, proper bolting practice to provide leak tight pressure retaining joints includes pre-assembly inspection and cleaning requirements, use of specific bolting torquing patterns, increased application of torque through multiple passes, and verification of uniformity of the gasket compression. Post-bolting inspections include verifying contact between the fastener and flange and proper flange alignment. Guidance for proper preload is provided with desired torque values to ensure adequate gasket stress for leak tightness.</p> <p>Procedures used are:</p> <ul style="list-style-type: none"> • MPM M711Q-02, "Primary Manway Removal/Installation using HYDRA-TIGHT," Sections 7.6, 7.7, 7.8, 7.9. • MPM M711Q-03, "Handhole Cover and Instrument Opening Cover Removal/Installation," Section 7.2. • MPM M711Q-04, "Steam Generator Secondary Manway Removal/Installation," Section 7.2. • MPM M711Q-06, "Primary Manway Removal/Installation using NES/TENTEC," Sections 7.6, 7.7, 7.8, 7.9. • MPM M712Q-04, "Reactor Coolant Pump Internal Replacement," Sections 7.10, 7.11, 7.12. • MPM M713Q-01, "Pressurizer Manway Cover Removal/Installation," Section 7.2. • MPM BB-001, "Pressurizer Code Safety Valve Removal and Installation," Section 7.3, and • MGM MOOP-08, "Torque Guideline for Bolted Connections," Section 7.0. <p>These activities are performed when there are opportunities of removal and installation of the subject components for maintenance or scheduled inspections.</p>
AMPA024	B.2.1.8	Clarify how many tubes are plugged in each steam generator.	<p>The following is the status of Steam Generator tube plugging at the completion of the fourteenth Steam Generator Tube Inspection completed during Refueling Outage 15 (October 2006).</p> <p>A Steam Generator: 35 tubes plugged (0.62% total percentage plugged) B Steam Generator: 35 tubes plugged (0.62% total percentage plugged) C Steam Generator: 20 tubes plugged (0.36% total percentage plugged) D Steam Generator: 114 tubes plugged (2.03% total percentage plugged) Note: an additional 3 plugs are installed in A Steam Generator cold leg</p>

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			only, due to tube sheet drilling errors during manufacturing. No tubes are installed in those locations. Reference: ET 07-0005 "Results of the Fourteenth Steam Generator Tube Inservice Inspection"
AMPA025	B.2.1.8	Discuss if WCGS has plans to replace the existing steam generators.	The current economic model for the steam generators does not recommend replacement. This model is updated as conditions change. Wolf Creek has no plans to replace our steam generators.
AMPA026	N/A	Clarify which Regulatory Guide 1.54 (i.e., Revision 0 or Revision 1) is WCGS committed to.	USAR Appendix 3A states that WCGS is committed to Rev. 0 of RG 1.54 as described in Table 6.1-2.
AMPA027	N/A	Clarify if coating inspections are performed at WCGS. If yes, explain what is the basis for these coating inspections.	WCGS did not credit NUREG-1801 XI.S8 for aging management.
AMPA028	N/A	Explain what consideration does WCGS have for transport of coatings to the sump screens.	WCGS did not credit NUREG-1801 XI.S8 for aging management.
AMPA029	N/A	Clarify which aging management program will be used to manage the effects of aging of coatings during the period of extended operation.	WCGS did not credit NUREG-1801 XI.S8 for aging management.
AMPA030	N/A	ASME Code Section XI, IWE 3510.2, "Visual Examination of Coated and Noncoated Areas," states that "The condition of the inspected area is acceptable if there is no evidence of damage or degradation which exceeds the visual acceptance criteria specified by the Owner." Explain what is the acceptance criteria for coated surfaces.	Detailed visual examination acceptance criteria identifies the following conditions as rejectable for coated surfaces: <ul style="list-style-type: none"> - Cracking - Flaking - Blistering - Peeling - Discoloration - Deformation - Other signs of distress All rejectable indications require initiation of a Non-Conformance Report (NCR) and evaluation in accordance with the WCGS corrective action process.
AMPA031	B.2.1.18	Clarify which materials are included in the Buried Piping and Tanks Inspection Program. The LRA mentions steel, stainless steel, and ductile iron, clarify if there are any other materials. Clarify which materials are coated and which are not. Explain what types of coatings	The materials included in the buried piping and tanks inspection program include steel, stainless steel, ductile iron and gray cast iron. The following coatings are used: Stainless steel coatings: None Steel, ductile iron and gray cast iron coatings: Coal tar enamel (pipe),

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AMPA032	B.2.1.18	<p>are used for each type of material.</p> <p>Clarify if WCGS has buried tanks and, if so, what is the material of construction.</p>	<p>Coal tar epoxy (steel tanks)</p> <p>The emergency fuel oil storage tanks (carbon steel) are the only tanks in the scope of the buried piping and tanks inspection AMP.</p>
AMPA033	B.2.1.18	<p>The LRA states that leaks have been observed in buried piping. Clarify where these leaks have been observed and what corrective actions have been taken. Clarify what is the current frequency of buried piping inspections.</p>	<p>In 1987 the Engineering Study for Galvanic Corrosion on Underground Piping at WCGS discovered corrosion on multiple runs of buried piping that are in the scope of license renewal in the Fire Protection System and the Auxiliary Feedwater System. The corrosion discovered in the Fire Protection System piping was characterized as galvanic corrosion. Pitting was found on carbon steel piping that was directly connected to ductile iron piping. The study postulated that the corrosion in the Auxiliary Feedwater System was either due to stray current from the Fuel Oil System or galvanic corrosion due to the carbon steel piping becoming a sacrificial anode.</p> <p>Since the completion of the 1987 study there have been four occurrences of leakage due to corrosion of the external surface of buried components at Wolf Creek. Three of these leaks occurred in buried portions of the non-essential Service Water System, which are not within the scope of license renewal. An additional leak was discovered in Fire Protection System (KC) outside the Diesel Generator Building in 1997. Subsequent excavation in 1998 discovered loss of material due to pitting corrosion. The Fire Protection System corrosion resulted from a break in the protective coating.</p> <p>The Borated Refueling Water System and the Auxiliary Feedwater System have only short runs of pipe between pipe tunnels and buildings. The 1987 Engineering Study provides the only known documentation of corrosion related failure in the Auxiliary Feedwater System. In this case pitting corrosion was discovered on excavated carbon steel piping. This section of piping was then replaced from the condensate storage tank to the power block. There have been no documented external corrosion related failures of the Borated Refueling Water System.</p> <p>The Emergency Fuel Oil System has only short runs of pipe from between the below grade fuel oil storage tank and the Diesel Generator Building. There have been no documented external corrosion related failures of the Emergency Fuel Oil System piping.</p> <p>The Essential Service Water System has multiple long runs of carbon steel piping. There are no documented external aging failures of the buried Essential Service Water System piping.</p>

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			<p>The Fire Protection System has four recorded discoveries of pitting corrosion, with two of these resulting in leakage. Three of these discoveries were made during the 1987 Engineering Study with one leakage among that group. The last recorded leakage occurred in 1997 outside of the Diesel Generator Building with pitting corrosion, due to a break in the protective coating.</p> <p>WCGS has no current buried piping inspection procedures. However, work control procedures require evaluation/repair of degraded conditions that are discovered.</p>
AMPA034	B.2.1.19	Clarify if there are any socket welds identified as high safety significant locations as part of the RI ISI program. If so, clarify how many are there. The EPRI Topical report specifies that high safety significant locations be volumetrically examined. Explain how socket welds will be examined if they are in a high safety significant location.	There are no socket welds identified as high safety significant locations as part of the RI ISI program.
AMPA035	B.2.1.27	Clarify if there have been any containment liner plate inspection results since 1996. If not, explain why. If yes, the results should be made available during the audit.	<p>The following Owner's Activity Reports document the containment liner plate inspections since 1996.</p> <p>Containment Inservice Inspection Program First Interval, First Period 2002 Findings:</p> <ul style="list-style-type: none"> - There were no components containing flaws or relevant conditions that required an evaluation to determine acceptability for continued service. - There were no Class MC components that required repairs, replacements, or corrective measures for continued service. <p>Containment Inservice Inspection Program First Interval, Second Period 2006 Findings:</p> <ul style="list-style-type: none"> - A general visual exam found localized pitting in the liner floor of the incore tunnel sump. - A detailed visual exam was performed to determine the magnitude and extent of degradation to the incore tunnel sump liner. Pitting was the only degradation found. It is believed that the pitting resulted from nearby welding, which damaged the coating. An evaluation performed by design engineering determined that the remaining wall thickness is sufficient and that recoating the pitted area with a qualified coating will stop further

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			<p>degradation. The pitted areas have been recoated with a qualified coating. The incore tunnel sump liner was found to be acceptable for continued service, and the areas containing the pitting were identified for reexamination during the next inspection period.</p> <ul style="list-style-type: none"> - The WCGS corrective action program addressed programmatic concerns. Applicable procedures were reviewed and revised as necessary to ensure compliance with IWE requirements and to establish acceptance criteria for pitting of the containment liner plate. <p>Containment Inservice Inspection Program First Interval, Third Period 2007</p> <p>Findings:</p> <ul style="list-style-type: none"> - There were no containment liner plate components containing flaws or relevant conditions that required an evaluation to determine acceptability for continued service. - There were no repairs, replacements, or corrective measures performed on any Class MC or CC items during the period of this report that were required due to an item containing a flaw or relevant condition that exceeded acceptance criteria.
AMPA036	B.2.1.27	The ASME Section XI, Subsection IWE Program operating experience describes degradation found in the in core instrument tunnel sump in 2002 and 2003. Discuss all preventive maintenance and corrective actions taken for each type of degradation found.	<p>A detailed visual exam was performed to determine the magnitude and extent of degradation to the incore tunnel sump liner. Pitting was the only degradation found. It is believed that the pitting resulted from nearby welding, which damaged the coating. An evaluation performed by design engineering determined that the remaining wall thickness is sufficient and that recoating the pitted area with a qualified coating will stop further degradation. The pitted areas have been recoated with a qualified coating. The incore tunnel sump liner was found to be acceptable for continued service, and the areas containing the pitting were identified for reexamination during the next inspection period.</p> <p>The WCGS corrective action program addressed programmatic concerns. Applicable procedures were reviewed and revised as necessary to ensure compliance with IWE requirements and to establish acceptance criteria for pitting of the containment liner plate.</p>
AMPA037	B.2.1.28	The LRA and its commitment list references ASME Code Section XI, 2003 Edition, which does not exist. Clarify this inconsistency.	LRA Section B2.1.28 and LRA Commitment number 15 for ASME Section XI, Subsection IWL (RCMS 2006-212) will be amended to read, "ASME Code Section XI, 2001 Edition with 2002 and 2003 addenda."
AMPA038	B.2.1.28	The LRA states that in 2005, a 20-year tendon surveillance found some excessive grease void volumes. Explain in detail your surveillance	During the twentieth year surveillance of the post-tensioning system, four tendons were found to accept greater than 10% of the tendon duct volume of grease when refilled after testing, with the highest being 17.4%.

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		results and justify your conclusions.	<p>These conditions were evaluated by design engineering and found not to be significant conditions. The apparent cause of these excess voids was determined to be an elevated initial filling temperature along with a short soak time, resulting in increased shrinkage. Examination of the tendons found no deterioration. The engineers also consulted a study conducted at Callaway Nuclear Station, addressing a similar condition with their unbonded tendons. The essential criterion for the operability of the sheathing filler material is to prevent corrosion of both the tendon wires and the anchorage components. The material used at the Callaway Plant, and at WCGS, accomplishes this by a characteristic which gives the filler material an affinity to adhere to steel surfaces, its ability to emulsify any moisture in the system nullifying its rusting ability, and by its resistance to moisture, mild acids, and alkalis. In addition, protection is afforded by each tendon wire being individually pre-coated prior to installation. Therefore, no further action was recommended.</p>
AMPA039	B.2.1.31	<p>Provide details on the operating experience relating to the degradation found in 2002-2003. Explain how does this compare to the 1998 established baseline. Include the acceptance criteria for cracking, deterioration, missing anchor bolts, anchor bolts pop outs, and the presence of water. Clarify if a scope expansion was required due to unacceptable conditions identified. Identify any additional inspections scheduled for the next inspection period.</p>	<p>Based on the 1998 baseline inspections, several masonry walls in the Control Building and Turbine Building had aging effects classified as "Acceptable With Degradation." Subsequent inspections that took place between 2002 and 2003 are summarized as follows:</p> <p>A masonry wall in the control building had cracks visible on both sides. The cracks were repaired with grout, but the joint was moving enough to re-crack the repair. The wall is located in an area not subject to weather or a threat to water exposure. Design engineering evaluated this condition and determined that there had been no change in the described conditions since the previous inspection, and the described condition is not indicative of any structural concern. This item was re-categorized as "Acceptable With Minor Degradation," and will be re-inspected during the next scheduled inspection.</p> <p>Several masonry walls in the turbine building were observed to have minor cracks categorized as "Acceptable With Degradation." In most cases during the 5-year re-inspection, the conditions had stabilized from the baseline observation resulting in a downgraded category. In the north wall of the southeast turbine building truck bay, a previous attempt had been made to repair the crack and was not accessible from the opposite side due to a building column. No leakage is involved that could lead to corrosion. The latest inspection reveals that the length and size of crack continues to increase. Design engineering has evaluated this wall and determined that it will still perform its intended functions.</p> <p>A support angle attached to a masonry wall was found to be missing an</p>

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			<p>anchor bolt. The angle supports the building's metal siding and is not a seismic support for the wall. This situation was evaluated by design engineering, who determined that no further action was required due to the redundancy of the design.</p> <p>Several pop outs around anchor bolts or through-bolts were identified. All of these were determined to have occurred during construction, and not as a result of aging. Design engineering evaluated all of the cases and determined that the damage did not prevent any of the components from performing their intended functions. None were found to have increased degradation during subsequent inspections.</p> <p>No operating experience pertaining to the presence of water in masonry walls was found.</p> <p>No scope expansion was required. All items that remain classified as "Acceptable with Degradation" will be inspected again during the next inspection period. No cases of "Major degradation" were found.</p>
AMPA040	B.2.1.32	The Structures Monitoring Program operating experience describes that degradations were addressed (e.g., minor degradation, corrosion on a hanger in the essential service water system, corrosion on a steel column, etc.) Discuss the above categories, the assessment performed, future monitoring recommended, and any corrective actions taken to prevent reoccurrences.	The WCGS Structures Monitoring Program identifies each structural component in-scope for license renewal and its inspection attributes. All conditions of degradation are identified, assessed, and categorized in accordance with ACI 201.1R, and ACI 349.3R. Specific limits for each type of degradation are provided in applicable WCGS procedures. The Structures Monitoring Program also specifies actions to be taken for each category of degradation. These actions may include future monitoring, further assessment, or corrective action. For the two examples cited in the question, the affected areas have been cleaned and re-coated.
AMPA041	B.2.1.32	<p>Provide the following information about the aging management of inaccessible concrete:</p> <p>(a) Submit the dates and results (at specific locations, not averages or ranges) of all past groundwater monitoring tests.</p> <p>(b) Discuss why the groundwater is non aggressive, and/or aggressive, if applicable.</p>	<p>(a) Groundwater monitoring tests conducted monthly at WCGS from June 2005 to May 2006 show the groundwater and soil to have pH values between 7.0 and 8.7, chloride solutions ranging from 5.0 ppm to 41.2 ppm, and sulfate solutions from 30 ppm to 717 ppm. These tests were conducted at five different locations on-site.</p> <p>The sulfate concentration of 717 ppm was from a well located north of the circulating water greenhouse. This well showed sulfate levels that were consistently higher than any other sample location. There are no external sources in the vicinity that could account for the elevated levels of sulfate at that location. Therefore, they are judged to exist as part of the natural environment. It should also be noted that the maximum level of sulfate</p>

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		<p>(c) Clarify if the Structures Monitoring Program will continue to perform the groundwater monitoring and inspect all inaccessible areas that may be exposed by excavation, whether the environment is considered aggressive or not.</p> <p>(d) Clarify if the Structures Monitoring Program will inspect any inaccessible areas that are exposed to the same environment which has caused significant concrete degradation in accessible areas.</p>	<p>concentration of 717 ppm is less than half of the limit of 1500 ppm as specified in NUREG 1801, Item II.A1-4.</p> <p>(b) Question withdrawn by NRC.</p> <p>[c] The structures monitoring program will be enhanced to monitor groundwater for pH, sulfates, and chlorides. Two samples of groundwater will be tested every five years.</p> <p>For inaccessible areas opportunistic inspections will be performed, if practical, whenever the area becomes accessible as a result of refueling outages, power curtailments, maintenance activities, excavations, etc.</p> <p>(d) Evaluation of inaccessible areas provides justification for their adequacy, which might include site-specific characteristics, accessible areas subject to similar conditions, industry experience, industry guidance and previous inspections of similar areas. The responsible-in-charge engineer initiates activities necessary to enable an inspection of any inaccessible areas that the evaluation can not provide reasonable assurance that the inaccessible components would be able to continue to perform their intended functions.</p> <p>LRA Sections A1.32 and B.2.1.32 and LRA commitment number 17 for Structures Monitoring Program (RCMS 2006-214) will be enhanced to monitor groundwater for pH, sulfates, and chlorides. Two samples of groundwater will be tested every five years.</p>
AMPA042	B.2.1.32	<p>Provide detailed operating experience for the degradation found in 2002/2003. Clarify if a scope expansion was required due to unacceptable conditions identified. Identify any additional inspections scheduled for the next inspection period.</p>	<p>All concrete structures and components that are in-scope for license renewal, and covered by the Structures Monitoring Program, are inspected and compared to acceptance criteria that are in accordance with ACI 201.1R and ACI 349.3R. Specific limits for each type of degradation are provided in applicable WCGS procedures.</p> <p>During the five-year reinspection in 2002/2003, only four items were identified to have increased aging effects. Two of those items previously categorized as "Acceptable with degradation" are not within the scope of license renewal. Two items that were previously categorized as "Acceptable with minor degradation" were noted to have increased aging effects and reclassified as "Acceptable with degradation". One was corrosion on an ESW hanger in the communications corridor, and the other was corrosion on a steel column in the turbine building.</p>

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			<p>Five new items categorized as "Acceptable with degradation" were reported during the 2002/2003 inspection. Platforms and ladders in the Auxiliary Building require painting. Grating in the Auxiliary Building has missing clips. Grating in the Diesel Generator Building has a loose clip. Structural steel in the Turbine Building has corrosion. These items have been corrected. Flashing on a roof hatch in the Auxiliary Building is cracked. This item will be monitored for future changes in aging effects.</p> <p>No scope expansion was required. All items that remain classified as "Acceptable with Degradation" will be inspected again during the next inspection period. No cases of "Major degradation" were found.</p>
AMPA043	B.2.1.32	Clarify if WCGS have any concrete beams, columns, and structure components (e.g., floor barriers, stairs, sumps, etc.) that are not currently identified in the Structures Monitoring Program. The current program evaluation report for the Structures Monitoring Program is not clear on this account.	The Structures Monitoring Program includes all concrete components in structures that are within the scope of license renewal and within the scope of the structures monitoring program.
AMPA044	B.2.1.32	Explain why the Structures Monitoring Program does not make reference to documents(s) or code(s) to be used as guidance for conducting a concrete condition survey and to evaluate the existing safety related concrete structures.	<p>The inspection methods, inspection frequency, and inspector qualifications are in accordance with WCGS procedures, which reference ACI 349.3R-96, ASCE 11-90, and ACI 201.1R-92.</p> <p>LRA Appendix B Section B2.1.32, Program Description, will be amended to include the above statement.</p>
AMPA045	B.2.1.33	Explain what is the baseline, the past, and the present survey reading (i.e, vertical movements) of the ultimate heat sink dam. Clarify what is the acceptance criteria and provide any operating experience related to this dam.	<p>The UHS dam is a normally submerged seismic Category I earthen structure whose side slopes and crest are protected with riprap. The crest of the dam was surveyed before being covered with riprap. The baseline survey of the settlement monuments was completed after construction and before filling of the cooling lake and the submergence of the UHS dam within the cooling lake. The settlement monuments are anchored within the dam embankment and project above the riprap.</p> <p>Current dam elevations are determined by subtracting the as-built top of monument elevation and as-built top of dam elevation from the current monument elevation.</p> <p>The UHS dam elevation is required to be at or above elevation 1070 MSL. The baseline elevation for the crest of the dam was 1070.30 MSL. The</p>

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			most recent elevation was found to be 1070.24. The top of dam elevation has always been acceptable.
AMPA046	B.2.1.33	The ultimate heat sink is currently using ACI 201.1R as a guide for conducting concrete condition surveys. The LRA does not mention how the condition of existing concrete structures will be evaluated. Provide a description of these evaluations and its justifications.	Question withdrawn by NRC.
AMPA047	B.2.1.33	The Water Control Structures Program operating experience indicates that the main dam, service and auxiliary spillways were repaired. Discuss when these repairs occurred and why the repairs were made	<p>The upstream main dam surface was repaired in 2001 near the water line with additional riprap due to the degradation and exposure of the sand and gravel riprap base at several locations. The 2004 surveillance report noted that riprap slope protection was in good condition and the repair work completed in 2001 has adequately corrected deficiencies noted in the 1999 inspection. The main dam is not in scope for license renewal as it is not relied upon to safely shut down the plant and is under the jurisdiction of the Kansas Department of Agriculture, Division of Water Resources.</p> <p>The 1999 surveillance report discusses the condition of the service spillway. Some popouts and spalling have occurred and are being repaired as needed. The ogee crest was grouted prior to 1999 and some minor seepage is returning. Emerging trees have been removed along the spillway channel between 1994 and 1999. The 2004 report stated that previous patching and grouting was holding up well. However, in 2006, it was found that the previous repairs at joints in the floor of the service spillway chute have numerous shrinkage cracks. Some of the repairs have broken loose exposing the original concrete. A Work Order was generated to address this condition.</p> <p>Some random cracking and spalling along the concrete auxiliary spillway have been noted several times. The cracks were evaluated in 1999 as not likely to indicate any serious deficiencies. The approach and discharge channels have had vegetation removed in the past and were reported clear of obstructions in the 2004 surveillance.</p>
AMPA048	B.2.1.1	In Section B2.1.1 (ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD), the LRA identifies six (6) exceptions to GALL AMP XI.M1. These exceptions	The LRA will be amended to incorporate changes to Sections A1.1 and B2.1.1 to remove reference to ASME code cases, RI-ISI, or alternatives required by 10CFR50.55a. There will be one exception to NUREG 1801 as follows:

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		<p>include use of specific ASME Section XI code cases, use of risk informed ISI, and use of alternatives required by 10CFR50.55a.</p> <p>The license renewal process has not included approval to use risk-informed ISI or approval to use specific ASME Section XI code cases.</p> <p>Please clarify why these items are included in the LRA description of the program.</p>	<p>NUREG 1801 AMP XI.M1 specifies the use of ASME Section XI 2001 Edition with addenda 2002 and 2003. WCGS ASME Section XI ISI Program uses ASME Code 1998 Edition through the 2000 addenda for the third 10 year inspection interval. WCGS will use the ASME Code Edition consistent with the provisions of 10CFR50.55a during the period of extended operation.</p> <p>(a) The above stated exception applies to NUREG 1801 Elements 1, 3, 4, 5, 6, and 7.</p> <p>(b) The same exception statement applies to each of the NUREG 1801 Elements 1, 3, 4, 5, 6, and 7 as follows:</p> <p>NUREG 1801 AMP XI.M1 specifies the use of ASME Section XI 2001 Edition with addenda 2002 and 2003. WCGS third interval ISI Program is using ASME Section XI 1998 Edition through 2000 addenda. Use of the 1998 Code through 2000 addenda is consistent with provisions in 10CFR50.55a to use the ASME Code in effect 12 months prior to the start of the inspection interval. WCGS will use the ASME Code Edition consistent with the provisions of 10CFR50.55a during the period of extended operation.</p>
AMPA049	B.2.1.1	<p>LRA Table 3.1.1, item 3.1.1.16, states that, for Westinghouse Model 44 and 51 steam generators, if general and pitting corrosion of the shell is known to exist, additional inspection procedures are to be developed. LRA Section 3.1.2.2.4 states that "the steam generators at WCGS are Model F, so the augmented inspection is not applicable." The GALL Report, Volume 2, Line IV.D1 12 states that "This issue is limited to Westinghouse Model 44 and 51 Steam Generators where a high stress region exists at the shell to transition cone weld." However, USAR Section 5.4.2.2 states that "the Model F steam generator is similar in configuration to the Model 51 steam generator in Westinghouse</p>	<p>The upper and lower steam generator shell to transition cone welds are part of the WCGS ISI program. The subject welds of one steam generator are 100% UT examined per examination category C-A, Item C1.10. There have been no rejectable indications identified in the UT inspections of the upper and lower steam generator shell to transition cone welds.</p> <p>WCGS is not aware of any industry operating experience that has identified the presence of general or pitting corrosion of Westinghouse Model F steam generators.</p>

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		<p>supplied plants.” The operating experience described in the LRA does not include any discussion of WCGS steam generator inspection results.</p> <p>(a) Provide additional information about the recent inspection results for the Model F steam generators. Address whether the inspection methods used would be able to detect general and pitting corrosion of the shell and whether any general or pitting corrosion of the shell has been found in the past.</p> <p>(b) Discuss any operating experience regarding the high stress region at the shell to transition cone weld that is mentioned in the GALL Report, Volume 2, Line IV.D1 12.</p> <p>[c] Discuss any industry operating experience found related to general or pitting corrosion of Westinghouse Model F steam generators</p>	
AMPA050	B.2.1.1	<p>License renewal program evaluation report WCGS AMP B2.1.1 Rev. 1 describes the open items. However, the information seems to be incomplete.</p> <p>(a) Please review the document and determine whether some of the text is missing, or clarify the intention of the item as written.</p> <p>(b) The open item is numbered 1. Clarify if there are additional open items for this program.</p>	<p>(a) For clarification, the item refers to the initial issue of the WCGS document that specifies the ISI classification bases for the third WCGS ISI interval. The document has not yet been issued.</p> <p>(b) There is only one open item.</p>
AMPA051	B.2.1.3	<p>Since use of specific ASME Section XI code cases is approved under 10</p>	<p>The LRA will be amended to incorporate changes to Section B2.1.3 to remove reference to ASME code cases. There will be two exceptions to</p>

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		<p>CFR 50.55a, not as part of the 10 CFR 50.54, please clarify why discussions of specific code cases are included in the LRA.</p>	<p>NUREG 1801 as described below.</p> <p>First NUREG 1801 exception: NUREG 1801 AMP XI.M1 specifies the use of ASME Section XI 2001 Edition with addenda 2002 and 2003. WCGS ASME Section XI ISI Program uses ASME Code 1998 Edition through the 2000 addenda for the third 10 year inspection interval. WCGS will use the ASME Code Edition consistent with the provisions of 10CFR50.55a during the period of extended operation.</p> <p>(a) The above stated exception applies to NUREG 1801 Elements 1, 3, 4, 5, 6, and 7.</p> <p>(b) The same exception statement applies to each of the NUREG 1801 Elements 1, 3, 4, 5, 6, and 7 as follows:</p> <p>NUREG 1801 AMP XI.M1 specifies the use of ASME Section XI 2001 Edition with addenda 2002 and 2003. WCGS third interval ISI Program is using ASME Section XI 1998 Edition through 2000 addenda. Use of the 1998 Code through 2000 addenda is consistent with provisions in 10CFR50.55a to use the ASME Code in effect 12 months prior to the start of the inspection interval. WCGS will use the ASME Code Edition consistent with the provisions of 10CFR50.55a during the period of extended operation.</p> <p>Second NUREG 1801 exception: NUREG 1801, Section XI.M3 specifies the use of NRC Regulatory Guide 1.65, "Material and Inspections for Reactor Vessel Closure Studs" for reactor head closure studs and nuts. WCGS uses NRC Regulatory Guide 1.65 except (a) modified SA-540, Grade B-24 stud material is used, (b) stud bolting material was procured with a minimum yield strength of 130 ksi and a minimum tensile strength of 145 ksi, (c) volumetric inspection of removed studs is performed per the ASME Section XI Code.</p> <p>(a) The above stated exception applies to NUREG 1801 Elements 1 and 7.</p> <p>(b) The same exception statement applies to NUREG 1801 Elements 1 and 7 as follows:</p> <p>NUREG 1801, Section XI.M3 specifies the use of NRC Regulatory Guide 1.65, "Material and Inspections for Reactor Vessel Closure Studs" for</p>

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			<p>reactor head closure studs and nuts. WCGS is committed to Regulatory Guide 1.65 with three exceptions. These are discussed in USAR Appendix 3A as follows:</p> <ol style="list-style-type: none"> 1. Modified SA-540, Grade B-24 stud material is used - The use of this material is within the limitations discussed in Regulatory Guide 1.85, Materials Code Case Acceptability 2. Stud bolting material that does not exceed 170 ksi tensile strength is used - The closure stud bolting material is procured to a minimum yield strength of 130 ksi and a minimum tensile strength of 145 ksi. This strength level is compatible with the fracture toughness requirements of 10CFR50, Appendix G (paragraph I.C), although higher strength level bolting materials are permitted. Additional design considerations that permit visual and/or nondestructive inspection and prevent exposure to borated water also apply 3. Inservice Inspection of the reactor vessel closure studs is performed with the ASME Code 1998 Edition through the 2000 addenda for the third 10 year inspection interval. Volumetric inspection of removed studs is performed.
AMPA052	B.2.1.3	Provide additional information (e.g., results of testing on the actual WCGS stud and nut material) beyond the discussion provided in USAR Appendix 3A to substantiate that the maximum tensile strength of the reactor closure studs and nuts is less than 170 ksi.	Copies of Certified Material Test Reports (CMTRs) are provided in the AMP Program Evaluation Report (PER) binder showing that the maximum tensile strength of the reactor closure studs and nuts is less than 170 ksi.
AMPA053	B.2.1.21	<p>The GALL Report scope of the program description for AMP XI.M37 makes reference to "the licensee responses to Bulletin 88-09, as accepted by the staff in its closure letters on the Bulletin, and any amendments to the licensee responses as approved by the staff." A WCNOG response to NRC Bulletin 88-09 is provided in its letter WM 89-0015, dated January 18, 1989.</p> <p>Clarify if the letter dated January 18, 1989 is the response as accepted by the staff and if there have been any subsequent amendments to this</p>	There is no documented staff response to Wolf Creek letter WM 89-0015 dated January 18, 1989. There have been no Wolf Creek submittals amending letter WM 89-0015 dated January 18, 1989.

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		<p>response. Provide a copy of the staff's acceptance of the letter dated January 18, 1989, and any amendment, if applicable.</p> <p>Supplemental Request: Provide documentation of NRC acceptance of WCNOC response to Bulletin 88-09.</p> <p>The NRC has accepted an action item to determine if a generic response was issued.</p>	
AMPA054	B.2.1.21	<p>The monitoring and trending of the Flux Thimble Tube Inspection Program license renewal program evaluation report states: "During each outage, all flux thimble tubes are inspected. If the predicted wear (as a measure of percent through wall) for a given flux thimble tube is projected to exceed the established acceptance criteria prior to the next outage, corrective actions are taken to reposition, cap or replace the tube." However, WCNOC procedure RXE 03-006, "Incore Flux Thimble Wear Assessment," step 6.2.5, appears to implement a conditional eddy current testing.</p> <p>Describe the inspections discussed in the license renewal program evaluation report. Clarify if this is an inspection using eddy current tests performed during the outage. Clarify the intention of step 6.2.5 in the procedure discussed above and whether this means that eddy current testing is conditional (i.e., based on predicted wear) rather than performed every outage.</p>	<p>The Wolf Creek Flux Thimble Tube Inspection Program performs eddy current testing that is conditional (i.e., based on predicted wear). The Flux Thimble Tube Inspection Program calculates predicted wear and verifies that wear is acceptable for the next two subsequent refuel outages. The refueling at which eddy current testing will be required is determined and will be one refueling before the wear reaches 60% through wall for the thimble with the greatest projected wear. Wear Trending of thimble tubes is documented as well as projected wear (% through wall) at the next cycle. Any thimble with wear in an active location greater than 60% through wall or projected to be greater than 60% before the next outage should be repositioned. Any thimbles with greater than 80% through wall or projected to be greater than 80% before the next outage are capped or equivalent and considered for future replacement.</p> <p>LRA sections B2.1.21 and A1.21 will be amended to state: "During each outage, flux thimble tube wear is evaluated and inspections performed based on evaluation results."</p>

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AMPA055	B.2.1.21	<p>Provide the following documentation during the audit:</p> <ul style="list-style-type: none"> • examples of flux thimble wear trending data sheets (e.g., RXE 03-006, Attachment A) • representative Flux Thimble Tube Program problem identification reports, work orders, etc, completed during previous refueling outages. <p>Supplemental Request:</p> <p>Provide additional detail (narrative) concerning data collected during RF15. Operating history summary.</p>	<p>A copy of RXE 03-006 including Attachment A (Wolf Creek Flux Thimble Wear Trending) that was completed during the October 2006 outage has been provided.</p>
AMPA056	B.2.1.5	<p>The PWSCC in nickel alloy penetration nozzles in the upper reactor vessel head currently is categorized as with low susceptibility. The revised NRC Order EA 03 009 requires that a bare metal visual examination meeting the requirements of IV.C.(5)(a) be performed every third refueling outage or every five years. In addition, it requires that a non visual NDE meeting the requirements of IV.C.(5)(b) be performed every four refueling outages or every seven years. The Nickel Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors Program operating experience provides a limited, somewhat indirect, discussion of the bare metal visual examination and no discussion of the non visual NDE.</p>	<p>A bare metal visual examination of the top of the Reactor Vessel Closure Head meeting the requirements of IV.C.(5)(a) was performed during RF15 (October 2006). No evidence of leakage was found.</p> <p>With exception of Vessel Head Penetration nozzles 77 and 78, a non-visual NDE examination of the Nickel Alloy penetration nozzles of the Reactor Vessel Closure Head meeting the requirements of IV.C.(5)(b) was performed during RF15 (October 2006). No indication of cracking was identified during the examination. See the response to question AMP A057 (B2.1.5-2) for the NRC staff authorized relaxation of the requirement for NDE inspections of VHP nozzles 77 and 78.</p>

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		<p>Discuss the results of these examinations. If they have not been performed, discuss the current schedule for each of these examinations.</p>	
AMPA057	B.2.1.5	<p>WCNOC letter dated October 5, 2006, "Relaxation Request from the First Revised NRC Order EA 03 009 Regarding Requirements for Nondestructive Examination of Nozzles Below the J Groove," requested a contingency relaxation of examination requirements for reactor pressure vessel penetration nozzles 74, 75, 76, 77, and 78.</p> <p>Provide a discussion on the current status of this request and whether the contingency relaxation of examination requirements was needed. If relaxation of examination requirements was needed, discuss whether this relaxation is an exception to the recommendations in GALL AMP XI.M11A and justify the exception.</p>	<p>During Refueling Outage 15, Wolf Creek performed a nonvisual NDE of Nozzles 74, 75, and 76 that met First Revised NRC Order EA-03-009. In NRC letter dated December 7, 2006, the NRC staff authorized relaxation of the requirement for NDE inspections of VHP nozzles 77 and 78 until inspection technology is developed to a state where the examination volume for the nozzles can be extended to be in full compliance with the order. The NRC staff safety evaluation found that Wolf Creek's proposed alternate inspection for VHP nozzles 77 and 78 to perform an ultrasonic examination from 2 inches above the highest point of the root of the J groove weld to the maximum extent practical, but not less than 0.30 inches below the toe of J-groove weld on the downhill side provides reasonable assurance of the structural integrity of the VHP nozzles.</p> <p>The relaxation of the requirement for NDE inspections of VHP nozzles 77 and 78 is not an exception because NUREG-1801 XI.M11A element 4 (Detection of Aging Effects) states in part: "Any deviations from implementing the appropriate required inspection methods of the Order, as amended, will be submitted for NRC review and approval in accordance with the Order, as amended." NRC letter dated December 7, 2006 authorized relaxation of the requirement for NDE inspections of VHP nozzles 77 and 78.</p> <p>Reference: 1. NRC incoming letter 06-00684, dated 12/07/2006 2. WCNOC letter ET 06-0035, dated 10/05/2006</p>
AMPA058	B.2.1.25	<p>The scope of GALL AMP XI.E2 includes electrical cables and connections (i.e., cable system) used in circuits with sensitive, high voltage, low level signals such as radiation monitoring and nuclear instrumentation that are subjected to aging management review. The scope of the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in</p>	<p>The cables and connections associated with the in-scope High Range Area Radiation Monitors (GTRE59, GTRE60) are subject to 10 CFR 50.49 environmental requirements and therefore are not included in this aging management program. The EQ package for the High Range Area Radiation Monitors is EQWP J-361A. See Program Evaluation Report (PER) B2.1.25 Section 5.1.</p>

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		Instrumentation Circuits Program only includes the ex core neutron monitoring system. Explain why high radiation monitor cables and connections are not included in the scope of the program.	
AMPA059	B.2.1.25	Identify any other sensitive, high voltage, low level signal circuits in addition to ex core neutron monitoring system at WCGS. Explain why these circuits are not within the scope of this program.	<p>The following is a list of the equipment which uses coax cables that could have sensitive, high voltage, low level signal circuits in addition to ex core neutron monitoring system at WCGS</p> <ul style="list-style-type: none"> High Range Area Radiation Monitors Containment Atmosphere Humidity Detectors Unit Vent Radiation Monitors Solid Radwaste System Radwaste Effluent Radiation Monitors Post Accident Sample System Sampling Panels Loose Parts Monitoring Solid Radwaste Spent Resin Primary Storage Tank Inlet Element and Control Station Balance of Plant Computer Public Address System (Intercom) Plant Security System Equipment. Generator Hydrogen & Carbon Dioxide System Miscellaneous Control Panels (Rad Cameras) In-Core Neutron Monitoring System Condensate Demineralizer System Acid Day Tank Level <p>The cables and connections associated with the in-scope High Range Area Radiation Monitors (GTRE59, GTRE60) are subject to 10 CFR 50.49 environmental requirements and therefore are not included the NUREG 1801 XI.E2 aging management program.</p> <p>Containment Atmosphere Humidity Detectors, Unit Vent Radiation Monitors, Radwaste Effluent Radiation Monitors, Post Accident Sample System Sampling Panels, Loose Parts Monitoring, Solid Radwaste Spent Resin Primary Storage Tank Inlet Element and Control Station, Balance of Plant Computer, Public Address System (Intercom), Plant Security System Equipment, Generator Hydrogen & Carbon Dioxide System, Miscellaneous Control Panels (Rad Cameras), In-Core Neutron Monitoring System, and Condensate Demineralizer System Acid Day Tank Level provide no license renewal intended functions and do not meet any criterion found in 10CFR54.4(a)(1), 10CFR54.4(a)(2), or 10CFR54.4(a)(3)</p>
AMPA060	B.2.1.25	GALL AMP XI.E2 states, in part, that	The ex core neutron monitoring system cables are not disconnected

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		<p>in cases where a calibration or surveillance program does not include the cabling system in the testing circuit, the applicant will perform cable system testing. Clarify if ex core neutron monitoring system cables are disconnected during calibration surveillance. If they are, explain why testing of these cables are not proposed.</p>	<p>during calibration surveillance. Ref Procedures: STS IC-431 "Channel Calibration NIS Source Range N-31" STS IC-432 "Channel Calibration NIS Source Range N-32" STS IC-440 "Channel Calibration NIS Intermediate Range and Power Range Detector High Voltage Plateaus"</p>
AMPA061	B.2.1.26	<p>GALL AMP XI.E3 defines medium voltage as voltage from 2 kV to 35 kV. The Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirement Program states that the in scope non EQ inaccessible medium voltage cables exposed to significant moisture simultaneously with significant voltage are 5 kV and 15 kV. Identify any inaccessible medium voltage cables that are from 2 kV to 35 kV. Explain why these cables are not subject to water tree aging effect and justify why they are not within the scope of the program.</p>	<p>The only medium voltage cables that are from 2 kV to 35 kV at WCGS are 5 KV and 15 KV cables. The scope of this program includes all of the in-scope inaccessible medium voltage cables at the WCGS.</p>
AMPA063	B.2.1.2	<p>Clarify when the EPRI 102134, Revision 6, was implemented.</p> <p>Follow Up Question B.2.1.2-1: In response to the question on when EPRI 102134, Revision 6 was implemented, the response stated that EPRI 102134, Rev. 6 does not exist. However, EPRI 100824, Rev. 6 replaced EPRI 102134 and was implemented on 10/11/2005. The program description in the application, and in the ten-element evaluation, EPRI 102134, Rev. 6 is referenced. Please clarify this</p>	<p>Pressurized Water Reactor Secondary Water Chemistry Guidelines - Revision 6 (EPRI 1008224) was incorporated in Revision 11 to the Secondary Chemistry Control procedure (AP 02B-001) on 10/11/2005.</p> <p>Response to Followup Question: In the LRA and in the 10-element review, where "EPRI 102134, Rev. 6", is used or referenced, it is incorrect. The correct reference in the LRA and 10-element review should be "Revision 6 of the EPRI Pressurized Water Reactor Secondary Water Chemistry Guidelines" (1008224).</p> <p>The Strategic Secondary Water Chemistry Plan, Rev. 2, was based on Rev 5 of the EPRI Secondary Water Chemistry Guidelines (102134). The Strategic Secondary Water Chemistry Plan, Rev. 3, was issued Mar. 13, 2007, and addresses Rev 6 of the EPRI Secondary Water Chemistry Guidelines (1008224). The LRA will be amended to reflect this</p>

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		<p>discrepancy. Furthermore, the Strategic Secondary Water Chemistry Plan – Rev 2 still addresses Rev. 5 of the EPRI guidelines, which we assume is EPRI 102134.</p> <p>Followup question for AMPA063 The GALL AMP XI.M2 “scope of program” program element states that water chemistry control is performed in accordance with the guidelines in (1) EPRI TR 105714, Revision 3, for primary water chemistry, (2) EPRI TR 102134, Revision 3, for secondary water chemistry, or (3) later revisions or updates of these reports as approved by the staff. The applicant’s Water Chemistry Program description states that the program monitors and controls known detrimental contaminants like chlorides, fluorides, and dissolved oxygen, by following the guidelines provided in EPRI TR 105714, Revision 5, for primary water chemistry and EPRI TR 102134, Revision 6, for secondary water chemistry. The LRA claims consistency with the GALL Report.</p> <p>Justify why the LRA does not take an exception when WCGS is not using the EPRI revisions recommended in the GALL Report. Provide a comparison of the GALL AMP referenced revisions to the LRA referenced revisions and explain why the use of a later version is acceptable by verifying that none of the controlled</p>	<p>information.</p> <p>Response to Followup Question 2: The GALL wording in the question was taken from NUREG-1801, Rev. 0. The GALL (NUREG-1801, Rev. 1) AMP XI.M2 “scope of program” program element states that “water chemistry control is in accordance with industry guidelines such as... EPRI TR-105714 for primary water chemistry in PWRs, and EPRI TR-102134 for secondary water chemistry in PWRs.” No EPRI revisions are specified in the scope of program element, therefore, no exception was taken with respect to EPRI revisions. The WCGS Water Chemistry Program is currently based on the EPRI PWR Primary Water Chemistry Guidelines, Rev. 5 and EPRI PWR Secondary Water Chemistry Guidelines, Rev. 6, with one exception as discussed in LRA B2.1.2.</p> <p>The following summarizes the key technical changes from Revision 5 to Revision 6 of the EPRI Secondary Water Chemistry Guidelines:</p> <p>Guidance was added in Chapters 1, 5, and 6 to clearly indicate the elements of the Guidelines that are mandatory and “shall” requirements under NEI 03-08, and those that are recommendations. The only mandatory requirement is to have a Strategic Water Chemistry Plan. “Shall” requirements include the Action Level 1, 2, and 3 control parameters and responses and the hold parameters in the control tables of Chapter 5 and 6, including both values and monitoring frequencies for these parameters, unless otherwise specifically indicated. The balance of the guidance elements provided in the Guidelines are recommendations.</p> <p>Chapter 2 was revised to reflect recent research regarding specific impurity effects on IGA/SCC, the effects of hydrazine on flow accelerated corrosion, and regarding the effects of amines on secondary side deposition processes.</p> <p>The treatment of deposit control practices was significantly modified in Chapter 3 to reflect current practices and currently available methods. Chapter 3 also contains an expanded discussion on thermal performance issues, and new sections on the loss of hydrazine scenario and startup oxidant control.</p> <p>The main discussion of integrated exposure was relocated from Appendix A to Chapters 4 and 7, and the discussion was revised to reflect its removal as a diagnostic parameter from Chapters 5 and 6. Chapter 4 was</p>

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		<p>parameters are relaxed in the later version.</p>	<p>also revised to include a list of items that should be covered in strategic water chemistry plans.</p> <p>Chapter 5 was revised to incorporate additional guidance regarding control of wet layup during short outages. The condition to which plants should go to as part of an Action Level 3 response was changed to "<5% power" from "hot or cold shutdown." The control tables for RSGs in Chapter 5 were thoroughly reviewed and edited. Some of the more significant changes to the tables were:</p> <ul style="list-style-type: none"> * Inclusion of Action Level 2 and 3 actions for loss of hydrazine. * Addition of a requirement that plants reduce power to below 5% if sodium, chloride, or sulfate exceed 250 ppb, or if they exceed 50 ppb for more than 100 hours, while between 5% and 30% power. * Reduction in the blowdown impurity level for sodium at the 30% hold from 20 to 10 ppb, and addition of an explicit recommendation that plants achieve sodium, chloride, and sulfate blowdown concentration below their respective Action Level 1 concentrations prior to exceeding 30% power. * Additional guidance was added such that plants are no longer required to go to Action Level 3 as long as the impurity concentration remains below Action Level 2 values. * Deletion of integrated exposure as a diagnostic parameter, and inclusion of lead and integrated corrosion product transport as diagnostic parameters. * Addition of a footnote to allow reduced frequency for sampling for copper for plants that are copper free or have confirmed low levels of copper transport (<20 ppt). <p>Chapter 6 – changes to Chapter 6 are not included as this refers to OTSGs and is not applicable to WCGS.</p> <p>Chapter 7 was revised to delete tables detailing sampling data requirements, to add more guidance regarding hideout returns, species to analyze in deposits, and integrated exposure evaluations, and to add a new section regarding effectiveness assessments. A discussion of lead sampling and additional recommendations on corrosion product transport sampling was also added.</p>

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AMPA064	B.2.1.2	<p>Explain the intent of the exception in the element of scope of the program. The exception states that WCGS is meeting the requirements for mixing the steam generator bulk solution. Clarify if this exception is related to the mixing or to the three samples per week. Clarify if this exception is also applicable to the parameters monitored or inspected program element. Clarify if this is an exception to GALL AMP XI.M2 element of scope of the program or if it is an exception to the EPRI 102314 guidelines.</p> <p>Follow-up Question B2.1.2-2: What is the basis for this exception? Do you have an analysis that states that a 33-hour recirculation of stem generators followed by weekly sampling is better than or equivalent to obtaining three samples per week until values are stable when in cold shutdown conditions?</p>	<p>The exception is to taking three samples per week. As explained in the evaluation, three samples per week are not necessary to demonstrate adequate mixing.</p> <p>This exception has been taken against Element 1, Scope of Program, and not against Element 3, Parameters Monitored or Inspected, although technically, the requirement the exception is taken against is contained in the EPRI Secondary Water Chemistry Guidelines, and not NUREG-1801.</p> <p>Follow up response:</p> <p>Wolf Creek Generating Station has taken exception to the Guideline "The steam generator bulk solution should be mixed and sampled three times per week (after parameters are in the normal range) until the parameters are stable, then mixed and sampled weekly." This statement is found in Section 5.5.1.2 of Revision 6 of the Guidelines as well as in Table 5-1.</p> <p>This exception is documented in the Strategic Secondary Water Chemistry plan. The exception was initially taken for Revision 5 of the Guidelines.</p> <p>This exception was taken based on operating experience/history. Prior to initial fill of the steam Generators (SG) during plant construction, calculations were performed to determine the required recirculation time to achieve mixing of the bulk solution. This calculation was based on the SG volume, flow-rate of the mix pumps, and recirculating three volumes of the bulk solution. The result was that a 33 hour recirculation time would thoroughly mix the bulk solution.</p> <p>The use of the 33 hour mix time became standard practice. Once in wet layup with chemicals added, SGs are mixed for 33 hours and then sampled to analyze for the desired chemical environment. Recirculation and sampling are then done weekly in accordance with AP 02-002, Chemistry Surveillance Program. Experience has shown that once the SG bulk solution meets required specifications, it remains satisfactory. If the parameters set forth in AP 02-003, Chemistry Specification Manual, are not met, adjustments are made and the recirc/sampling is repeated.</p>
AMPA065	B.2.1.2	<p>The PIR operating experience report summary states that this PIR does not address any license renewal aging effect. Clarify this statement.</p> <p>For example, PIR 20030900 addresses long standing anomalies</p>	<p>Specific operating experience items were said to address a license renewal aging effect only when an explicit mention of the aging was made. None of these PIRs identified any actual aging. In cases like the ones noted, where there was direct discussion of programmatic elements or the potential to affect aging, the operating experience item was linked to the AMP, designating it for further consideration during the AMP review.</p>

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		<p>regarding plant chemistry where increased levels of aggressive impurities such as chlorides and sulfates have been identified which could increase corrosion. Also, PIR 20021583 and PIR 20020270 address chemistry control issues of out of specified conditions that could impact corrosion.</p> <p>Follow-up Question 2.1.2-3: Response indicates that specific operating experience items were said to address a license renewal aging effect only when an explicit mention of the aging was made. None of these PIRs identified any actual aging.</p> <p>Review of PIR 20021583, under problem description section d, there are words that state that chiller chemistry analysis indicate that excessive corrosion and possibly crud deposits may have occurred due to level of chloride detected and the amount of solids in the chemistry sample. It also states that chemistry problems may be broader than simple chemical contamination.</p> <p>PIR 20020270 addresses higher pH. It also states that potential consequences are higher corrosion rate.</p> <p>Other PIRs reviewed address similar chemistry issues. Yet, element 10 evaluation states that there have been no major chemical excursions during WCGS operating history. Please explain what "Major" means.</p>	<p>Follow up Response:</p> <p>Although the water chemistry program is intended to maintain water chemistry parameters within specifications, it is recognized that water chemistry parameters may occasionally exceed the limits specified in the plant procedures. As the amount of departure from specifications increases action levels increase. Prompt graduated corrective actions are specified at each action level to eliminate or mitigate degradation from the out of specification condition. A "major" chemical excursion as discussed in the license renewal application is an event where one or more chemical species exceeded an action level and the procedurally specified corrective actions were not complied with. None of the PIRs identified address events when the procedurally specified corrective actions were not complied with.</p>

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		<p>Also, please justify in light of the PIRs identified above, why you believe there are no major chemistry excursions.</p>	
AMPA066	B.2.1.2	<p>Water Chemistry Program operating experience describes that the program was developed using industry experience. However, it does not address plant specific operating experience to confirm that the program, as implemented, will adequately manage aging effects. The 10 elements evaluation only addresses industry operating experience. Provide a summary of plant specific operating experience to provide reasonable assurance that aging effects will be adequately managed.</p> <p>Follow-up Question 2.1.2-4: In response to the request to provide a summary of plant operating experience in element 10, you responded that plant operating experience is referenced in AMP element 10. There is no reference to plant experience in element 10, except for one statement that there have been no major chemical excursions during WCGS operating history. Please provide specific plant experience that was used to determine that the program will adequately manage the aging effects.</p>	<p>Plant specific operating experience is referenced in AMP element 10. The evaluation provides a pointer to detailed discussions of numerous plant chemistry operating history issues and their resolution as described in station strategic plans. The discussion concludes by indicating that no major chemistry excursions have occurred during WCGS' operating history.</p> <p>Individual plant operating experience items were evaluated to determine relevance to actual aging effects/mechanisms and/or WCGS aging management programs. A particular operating experience item may have been linked to a specific AMP(s) and/or to one or more material/environment/aging effect combinations based on the actual content of the item. Operating experience items were said to address a license renewal aging effect only when an explicit mention of the aging was made. Likewise, where there was direct discussion of programmatic elements or the potential conditions to affect aging that were within the control of the program, the operating experience item was linked to the AMP.</p> <p>The operating experience items that were thusly linked to any material, environment, aging effect combinations, or to an AMP, were considered further during either the AMR phase, regarding which aging effects/mechanisms to assign, or during the AMP phase, as a potential input to Element 10.</p> <p>A number of plant corrective action documents and work orders that were evaluated as relating to the chemistry program are included on the Plant Aging Management Document Retrieval and Research System and will be included in hardcopy form in the AMP binder provided during the AMP audit. These operating experience items involve the areas of system chemistry performance, chemistry related system operation, chemistry control technical details, equipment degradation, benchmarking, self assessments, and program enhancements. The operating experience does not include any examples of equipment degradation challenging an intended function that is related to deficiencies in the chemistry program. The evaluation of this operating experience contributed to the conclusion that there is a reasonable assurance that aging effects will be adequately managed.</p>

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			<p>Follow up response:</p> <p>Out of specification values and unexplained adverse trends in water chemistry parameters are documented by a Condition Report. Two recent examples of this process include Condition Report 2006-001764 and Condition Report 2006-002233. The former example noted a large increase in turbine driven auxiliary feed water pump discharge conductivity, which was determined to be due to a leaking isolation valve from the emergency service water system (ESW). The corrective action included corrective maintenance to eliminate the in-leakage of ESW. The latter example documents the corrective actions taken in response to out of specification results for lithium concentration in the reactor coolant system. The action taken was to adjust the cation ion exchanger time in service.</p>
AMPA067	B.2.1.10	<p>Low flow and stagnant areas of plant heating and central chilled water systems could show crud build up. Explain why a verification program such as a one time inspection is not used to confirm that significant degradation is not occurring. Furthermore, explain why this is not considered as an exception to the detection of aging effects program element.</p> <p>Follow-up Question B2.1.10-1: The response does not address the question. The GALL Report AMP XI.M21 in element 4, "detection of aging effects" states:</p> <p>Control of water chemistry does not preclude corrosion or SCC at locations of stagnant flow conditions or crevices. Degradation of a component due to corrosion or SCC would result in degradation of system or component performance. The extent and schedule of inspections and testing should</p>	<p>Preliminary Response</p> <p>The plant heating and central chilled water systems are within the scope of license renewal per 10 CFR 54.4(a)(2) for spatial interaction concerns only. Therefore, the only component intended function applicable to these systems is (a)(2) pressure boundary. Crud buildup would not directly affect the intended function of these components. (Element 4)</p> <p>NUREG-1801 does not suggest that an inspection is the only satisfactory option in this situation. Specifically, Element 4 states "The extent and schedule of inspections and testing should assure detection of corrosion or SCC before the loss of the intended function of the component." This was interpreted to mean inspections and/or testing, as long as the loss of the intended function of the component was prevented. Periodic monitoring of the diagnostic chemistry parameters (testing) of copper and iron in the closed cooling water systems provides an indication of corrosion occurring on the system, and will assure detection of corrosion before the loss of the intended function of the component.</p> <p>Follow-up Response</p> <p>LRA B.2.1.10 will be amended to state the following exception to inspections and testing for systems in scope of license renewal due to 10CFR 54.4(a)(2) due to spatial interactions such as plant heating and central chilled water systems. LRA B.2.1.10 will be amended as follows to include this exception.</p> <p>Exceptions to NUREG-1801 Parameters Monitored or Inspected – Element 3, Detection of Aging</p>

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		<p>assure detection of corrosion or SCC before the loss of intended function of the component.</p> <p>Therefore, please explain why this is not considered an exception if you are not performing any inspection for plant heating and central chilled water system.</p>	<p>Effects – Element 4, Monitoring and Trending –Element 5, and Acceptance Criteria-Element 6</p> <p>“WCGS will not perform inspection or testing of plant heating and central chilled water systems. Plant heating and central chilled water systems are in the scope of license renewal due to 10CFR 54.4(a)(2) due to spatial interactions only. Therefore the only intended function applicable to these systems is pressure boundary. Crud buildup would not directly affect the intended function of these components.” The periodic sampling and maintenance of system chemistry within specified limits is adequate to manage aging before the loss of intended function.</p>
AMPA068	B.2.1.10	<p>For the exception on the parameters monitored or inspected, confirm if all component cooling water heat exchangers are periodically tested to measure heat transfer capability. Clarify if all heat exchangers are periodically NDE tested. If not, how are the heat exchangers selected for testing and inspection, and how are the results correlated to other component cooling water heat exchangers.</p>	<p>It is not clear if this question is referring to the main CCW heat exchangers only, or all heat exchangers that credit this AMP, so the answer will address both.</p> <p>The CCW heat exchangers are periodically tested to measure heat transfer capability. Flow and temperature measurements are used to calculate heat exchanger performance in terms of a fouling factor. Tube side (raw water) flow and differential pressure are also measured and used as an indicator of tube fouling. (Element 3)</p> <p>Emergency Diesel Generator (EDG) performance testing monitors and trends various engine parameters to ensure target availability goals are met or exceeded. The monitored engine parameters include intercooler water pump pressure, jacket water pump pressure, intercooler temperatures, and jacket water temperatures. Trending of these parameters will detect component aging prior to a loss of intended function. (Element 3)</p> <p>The CCW, EDG intercooler, and jacket water cooler heat exchangers (meaning all) are periodically NDE tested (ECT) to detect aging of the tube pressure boundary. (Element 4)</p> <p>GALL AMP XI.M21 states, for the "parameters monitored or inspected" program element, that this program should monitor the effects of corrosion by surveillance testing and inspections in accordance with standards in EPRI TR-107396 to evaluate system and component performance. For heat exchangers, the parameters monitored include flow, inlet and outlet temperatures, and differential pressure. Various CCW supplied heat exchangers, such as the letdown heat exchangers, residual heat removal heat exchangers, safety injection pump coolers, and the PASS sample coolers, are not periodically tested for flow, inlet and outlet temperatures,</p>

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			<p>and differential pressure. The CCW heat exchangers are periodically tested to measure heat transfer capability. Shell-side (closed-cycle cooling water) flow and temperature measurements are used to calculate heat exchanger performance in terms of a fouling factor. Tube side (raw water) flow and differential pressure are also measured and used as an indicator of tube fouling. The CCW heat exchangers are periodically NDE tested (ECT) to detect aging of the tube pressure boundary.</p> <p>The performance monitoring and NDE of the CCW heat exchangers will provide a leading indicator that aging resulting in a loss of material and fouling of heat exchangers is effectively managed in the CCW system. An enhancement to the WCGS closed-cycle cooling water system program, identified in Element 5, to specify inspection of the internal surfaces of the CCW pump return line check valves during In-Service Testing activities will also provide additional indicators of the effective management of the effects of aging due to loss of material and fouling in the CCW system. A review of WCGS plant specific operating experience indicates there has been no evidence of significant fouling or loss of material observed in the closed cooling systems. In conclusion, the current heat exchanger performance monitoring, internal inspections activities (in conjunction with check valve IST), and CCW system operating experience will be proposed instead of performance testing of all CCW supplied heat exchangers to demonstrate that CCW chemistry program is effective in managing the aging effects in the CCW system. (Element 3)</p>
AMPA069	B.2.1.12	<p>LRA Section B2.1.12 states that "approximately 10 percent of each type of penetration seal (electrical and mechanical as practical) is visually inspected at least once every 18 months." GALL AMP XI.M26 states that 10 percent of each types of penetration seal should be visually inspected to examine any degradation. Since 10 percent of each type (electrical and mechanical as practical) of penetration seal is not the same as 10 percent of each type of seal, please clarify if the 10 percent population of penetration seal includes all types of seals (e.g., cables trays, conduits, pipes, ducts,</p>	<p>FIRE BARRIER PENETRATION SEALS</p> <p>The requirement for penetration seal inspection is contained in Section 6.3.11.8 of AP 10-100, Fire Protection Program, which states the following;</p> <p>"STN FP-452, FIRE BARRIER PENETRATION SEALS INSPECTION, is performed at least once per 18 months to visually inspect approximately 10% of electrical and mechanical Penetration Seals. If Fire Protection determines that inspection results present an adverse trend, an additional population of the affected penetration sealing device type shall be inspected for acceptability. The number of penetration sealing devices inspected in this effort shall meet or exceed the total number of the affected type inspected in the original set. This process shall be repeated until satisfactory results are obtained for the affected penetration sealing device type. Samples shall be selected such that each Penetration Seal will be inspected every 15 years."</p>

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		and seismic gaps.)	<p>An approximate 10% inspection arrangement for mechanical and electrical penetration seals allows flexibility in development and maintenance of the penetration seal inspection sets. Ten inspection sets have been developed by Fire Protection to ensure that all penetration seals separating safety-related fire areas or separating portions of redundant systems important to safe shutdown are inspected every 15 years. The inspection sets were developed based on previous penetration seal inspection dates with each set approaching an approximate 10% sample of electrical and mechanical penetration seals. As penetrations are added, revised, or deleted, throughout plant life, the total number of mechanical and electrical penetration seals change and resulting inspection set totals change. It is not prudent to shift penetrations from one selection set to another just to maintain a 10% overall selection set. Additionally, some seal types have been used on a limited basis, which would result in repeat inspections of seals within the 15 year time frame, if selection sets were solely based on seal type.</p> <p>The AP 10-104 penetration seal surveillance requirements provide an acceptable methodology for implementation of the penetration seal inspection program, while ensuring that each penetration seal separating safety-related fire areas or separating portions of redundant systems important to safe shutdown be inspected every 15 years. Additionally, these seal surveillance requirements are consistent with NUREG-1552, where the NRC documented their assessment of fire barrier penetration seal programs in nuclear power plants. Specifically, relevant excerpts from Section 5.7 of NUREG-1552 state the following:</p> <p>"...In general, the licensees inspect a portion of the total population of seals every refueling outage (about every 18 months). If penetration seals are found to be degraded or inoperable (e.g., breached, degraded, or improperly repaired), the licensees document the deficiencies and take the appropriate corrective actions....."</p> <p>"The staff had previously addressed potential problems in IN 88-04, IN 88-56, and IN 94-28 (See Appendix A). On the basis of the assessment documented here, it is the staff's view that existing licensee and vendor seal installation programs are adequate to prevent potential penetration seal installation problems. In the event seals are improperly installed or breached, or become degraded, existing licensee surveillance, maintenance, and repair programs are adequate to reveal and correct potential problems."</p>

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			<p>FIRE BARRIERS At least once per 18 months Wolf Creek performs a visual inspection of the exposed surface of each fire rated assembly (fire barriers separating redundant Post-Fire safe shutdowns systems) for the presence of breaches and gross deterioration. The 18 month fire rated assembly inspections include such items as seismic gap seals, cable tray fire stops, steel pipe caps, etc.</p>
AMPA070	B.2.1.12	<p>PIR 20012577 recommended removing penetration seals that are sealed with grout from the periodic 18 month penetration seal inspection. Confirm if this recommendation was implemented, and if so, clarify what is the inspection frequency for this type of penetration seals. If this frequency is different than the GALL Report recommended frequency, justify why this is not an exception.</p>	<p>Grouted penetration seals are part of the Fire Barrier visual inspections that are performed at least once per 18 months to detect the presence of breaches and gross deterioration.</p>
AMPA071	B.2.1.12	<p>The GALL Report states that no corrosion and mechanical damage of halon system is acceptable; no corrosion is acceptable in the fuel supply line; and no visual indications outside those allowed by approved penetration seal configurations for penetration seals. The Fire Protection Program License Renewal Evaluation Report states differently in the 10 program elements evaluation where the degradation is not acceptable if it prevents the system or penetration seal or fuel line from performing its intended function. Furthermore, the same document states for fuel supply line that leakage would indicate the potential of age related loss of material and would be observed and documented in the monthly operation of the diesel driven fire pump and corrective</p>	<p>Penetration Seals NUREG-1801 XI.M26 element 6 (acceptance criteria) states: "Inspection results are acceptable if there are no visual indications (outside those allowed by approved penetration seal configurations) of cracking, separation of seals from walls and components, separation of layers of material, or ruptures or puncture of seals." Acceptance criteria are defined in the WCGS procedures used to perform tests and inspections of the fire protection system. Fire barrier penetration seals inspection results are acceptable if there are no cracking, separation of seals from walls, separation of layers of materials, ruptures, or punctures of seals observed that might impact the seals fire protection functionality. Penetration seal inspection acceptance criteria is evaluated in M-663-00017A, Penetration Seal Typical Details. Inspections are performed by Level II (minimum) QC personnel certified for the type of sealing device being inspected.</p> <p>Diesel-driven fire pump fuel supply line: NUREG-1801 XI.M26 element 6 (acceptance criteria) states: "No corrosion is acceptable in the fuel supply line for the diesel-driven fire pump." NUREG-1801 XI.M26 element 4 (detection of aging effects) states: "Periodic tests performed at least once every refueling outage, such as flow and discharge tests, sequential starting capability tests, and controller</p>

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		<p>action would be initiated.</p> <p>Explain why these are not exceptions to the acceptance criteria program element, and provide a basis for why these are acceptable. Clarify who determines how significant the corrosion or leakage is before the intended function is impaired.</p> <p>Followup Questions: The response to question B2.1.12-3 does not answer the question.</p> <p>The GALL AMPXIM.26 element "detection of aging effects" recommends visual inspection of the halon system to detect any sign of degradation such as corrosion, mechanical damage, or damage to dampers. Also, element "Acceptance criteria" recommends any sign of corrosion and mechanical damage is not acceptable.</p> <p>The response stated that WCGS performs a functional deluge test to identify any mechanical damage. The halon system surveillance procedures STN FP-400A, 400B, 400C, etc. were reviewed. Neither of these procedures addresses visual inspection. Section 6.0, Acceptance Criteria, does not provide any criteria for corrosion or mechanical damage.</p> <p>Please clarify how WCGS meets this GALL Report recommendation and if not, please justify why an exception</p>	<p>function tests performed on diesel-driven fire pump ensure fuel supply line performance. The performance tests detect degradation of the fuel supply lines before loss of the component intended function."</p> <p>Performance testing of the diesel-driven fire pump is used to detect degradation (corrosion) of the fuel supply lines. Satisfactory performance of the diesel driven fire pump means that no degradation (corrosion) was detected. A monthly operation and fuel level check is performed on the diesel-driven fire pump and any leakage or any signs of corrosion that would prevent the system from performing its intended function are not acceptable. Leakage would indicate the potential of age related loss of material and would be observed and documented in the monthly operation of the diesel-driven fire pump and corrective action would be initiated. Diesel fire pump day tank level is checked once per shift in accordance with CKL ZL-009. This is also a data point for identifying system leakage.</p> <p>Halon System: NUREG-1801 XI.M26 element 6 (acceptance criteria) states: "Also, any signs of corrosion and mechanical damage of the halon/CO2 fire suppression system are not acceptable." NUREG-1801 XI.M26 element 4 (detection of aging effects) states: "Visual inspections of the halon/CO2 fire suppression system detect any sign of added degradation such as corrosion, mechanical damage, or damage to dampers. The periodic function test and inspection performed at least once every six months detects degradation of the halon/CO2 fire suppression system before the loss of the component intended function." Wolf Creek performs a functional deluge test of the halon fire suppression system to identify any mechanical damage of the halon fire suppression system that prevents the system from performing the intended functions.</p> <p>Follow-up response: The halon system has the internal environments of plant indoor air and dry gas. The following halon system materials have an internal environment of plant indoor air: galvanized carbon steel, and copper alloy. The following halon system materials have an internal environment of dry gas: bronze, carbon steel, galvanized carbon steel, cast iron, elastomer, copper alloy, and stainless steel. The material and environment combinations listed above do not require aging management per the AMR.</p> <p>Carbon steel and cast iron materials in the halon system are exposed to an external environment of plant indoor air and will be visually inspected by the XI.M36 External Surfaces Monitoring Program.</p>

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		<p>to the GALL Report is not taken.</p> <p>For diesel driven fire pump, the GALL Report element "acceptance criteria" recommends no corrosion is acceptable in the fuel oil supply line for the diesel driven fire pump.</p> <p>The response stated that performance testing of the diesel-driven fire pump is used to detect degradation (corrosion) of the fuel supply lines. Please explain how the performance test will detect corrosion.</p>	<p>The external surfaces of the diesel-driven fire pump fuel oil supply line will be visually inspected by the XI.M36 External Surfaces Monitoring Program.</p> <p>The diesel-driven fire pump fuel oil supply line has an internal environment of fuel oil and is made of carbon steel. The NUREG-1801 row referenced for this components configuration is VII.G-21, which recommends the aging management programs of XI.M26, Fire Protection, and XI.M30, Fuel Oil Chemistry. XI.M30 Fuel Oil Chemistry utilizes the XI.M32 One-Time Inspection to verify the effectiveness of the Fuel Oil Chemistry Program using a representative sample of components in systems that contain fuel oil.</p> <p>The first paragraph of LRA Section A1.12 will be amended to state the following:</p> <p>"The Fire Protection program manages loss of material for fire rated doors, fire dampers, diesel-driven fire pump, and the halon fire suppression system, cracking, spalling, and loss of material for fire barrier walls, ceilings, and floors, and hardness and shrinkage due to weathering of fire barrier penetration seals. Periodic visual inspections of fire barrier penetration seals, fire dampers, fire barrier walls, ceilings and floors, and periodic visual inspections and functional tests of fire-rated doors are performed. The internal surface of the diesel-driven fire pump fuel oil supply line is managed by the XI.M30 Fuel Oil Chemistry aging management program, which utilizes the XI.M32 One-Time Inspection to verify the effectiveness of the Fuel Oil Chemistry Program using a representative sample of components in systems that contain fuel oil, ensuring that there is no loss of function due to aging of diesel fuel oil supply line."</p> <p>The first paragraph of LRA Section B2.1.12 will be amended to state the following:</p> <p>"The Fire Protection program manages loss of material for fire rated doors, fire dampers, diesel-driven fire pump, and the halon fire suppression system, cracking, spalling, and loss of material for fire barrier walls, ceilings, and floors, and hardness and shrinkage due to weathering of fire barrier penetration seals. Periodic visual inspections of fire barrier penetration seals, fire dampers, fire barrier walls, ceilings and floors, and periodic visual inspections and functional tests of fire-rated doors are</p>

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			<p>performed. The internal surface of the of the diesel-driven fire pump fuel oil supply line is managed by the XI.M30 Fuel Oil Chemistry aging management program, which utilizes the XI.M32 One-Time Inspection to verify the effectiveness of the Fuel Oil Chemistry Program using a representative sample of components in systems that contain fuel oil, ensuring that there is no loss of function due to aging of diesel fuel oil supply line."</p> <p>The fifth paragraph of LRA Section B2.1.12 will be amended to state the following:</p> <p>"The Fire Protection program performs a visual inspection, at least once per year, on fire rated doors to verify the integrity of door surfaces and for clearances to detect aging of the fire doors. The internal surface of the of the diesel-driven fire pump fuel oil supply line is managed by the XI.M30 Fuel Oil Chemistry aging management program, which utilizes the XI.M32 One-Time Inspection to verify the effectiveness of the Fuel Oil Chemistry Program using a representative sample of components in systems that contain fuel oil, ensuring that there is no loss of function due to aging of diesel fuel oil supply line. A visual inspection and function test of the halon fire suppression system is performed every 18 months."</p>
AMPA072	B.2.1.13	<p>The Fire Water Program license renewal program element report refers to Fire Protection Program in all elements. Clarify if the Fire Protection and Fire Water System Programs are interchangeable. Clarify if this the same Fire Protection Program addressed in LRA Section B2.1.12.</p>	<p>The Fire Water system is a subsystem of the Fire Protection system. The Fire Water AMP (XI.M27, LRA Section B2.1.13) addresses water-based fire protection components such as sprinklers, nozzles, hydrants, standpipes, hose stations and water storage tanks (buried fire water piping external surfaces are managed by the Buried Piping and Tanks Inspection program). The Fire Protection AMP (XI.M26, LRA Section B2.1.12) addresses fire rated doors, fire dampers, diesel-driven fire pump, fire barrier walls, ceilings and floors, barrier penetration seals and the halon fire suppression subsystem. Although both AMPs manage components in the WCGS Fire Protection system, they are not interchangeable because NUREG-1801 creates a separate division of responsibility for managing aging of the Fire Protection system components. Although NUREG-1801 creates this division, at WCGS there is no division between the two and all Fire Protection system components are governed by one program procedure (AP 10-100, Fire Protection Program). Thus, both the Fire Protection AMP XI.M26, and Fire Water AMP XI.M27 will refer to the "Fire Protection Program".</p>
AMPA073	B.2.1.13	<p>Describe how the visual inspection performed under the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components</p>	<p>NUREG 1801, XI.M27, Fire Water System states that fire protection system piping is to be subjected to required flow testing in accordance with guidance in NFPA 25 to verify design pressure or evaluated for wall thickness, and that visual inspections can be used to satisfy this</p>

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		<p>Program referenced in the Fire Water System Program evaluates wall thickness.</p>	<p>evaluation. Visual inspections performed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program would detect wall thinning by identifying corrosion, surface or finish discontinuities, or a lack of symmetry of the component dimensions. If degradation is unacceptable, deficiencies would be resolved via WCNOCs corrective action program. The WCNOC corrective action program may then specify mechanical or NDE methods to be used in quantifying the degradation consistent with QCP 20-518, "Visual Examination of Heat Exchangers and Piping Components" or other approved station procedures. (WCGS-AMP-B2.1.22, Section 3.6, QCP 20-518).</p>
AMPA074	B.2.1.13	<p>The Fire Water System Program description states that visual inspections of the fire protection system exposed to water, evaluating wall thickness to identify evidence of loss of material due to corrosion, is covered by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. However, the detection of aging effects program element in the GALL AMP states that these inspection must be capable of evaluating (1) wall thickness to ensure against catastrophic failure and (2) the inner diameter of the piping as it applies to the design flow of the fire protection system.</p> <p>Since the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is a new program, discuss how this program will evaluate wall thickness and the inner diameter of the piping by only performing visual inspection.</p>	<p>Visual inspections performed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program would detect wall thinning by identifying corrosion, surface or finish discontinuities, or a lack of symmetry of the component dimensions. If degradation is unacceptable, deficiencies would be resolved via WCNOCs corrective action program. The WCNOC corrective action program may then specify mechanical or NDE methods to be used in quantifying the degradation consistent with QCP 20-518, "Visual Examination of Heat Exchangers and Piping Components" or other approved station procedures. (WCGS-AMP-B2.1.22, Section 3.6, QCP 20-518).</p>
AMPA075	B.2.1.13	<p>The GALL AMP recommends annual fire hydrant hose hydrostatic tests. The Fire Water Program states that hydrostatic test of hoses occurs once every 3 years. Justify and provide a basis for this 3 year</p>	<p>WCGS USAR Table 9.5E-1, Section III.E, "WCGS Fire Protection Comparison to 10CFR50 Appendix R", states that interior standpipe hose is tested every three years or the fire hose is replaced every five years. This is part of the WCGS current licensing basis. Since this is part of the approved licensing basis, clarification as to previous branch technical positions and commitments would not be applicable. However, for</p>

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		<p>frequency. Clarify if hydrostatic test frequency of hoses once every 3 years is documented in the WCGS Fire Protection Program and in commitments to 10 CFR 50.48 using the Branch Technical Position (BTP) Auxiliary and Power Conversion Systems Branch (APCSB) 9.5 1, "Guidelines for Fire Protection for Nuclear Power Plants," dated May 1, 1976, and BTP APCS 9.5 1, Appendix A, dated August 23, 1976.</p> <p>WCGS also states that it may replace an existing fire hose with a new fire hose every five years in lieu of performing a hydrostatic test. This implies that the fire hydrant hose will not be tested in five years. Justify how WCGS ensures that the hose has not degraded within these five years and will perform its intended function if no testing has been performed.</p>	<p>information purposes, hydrostatic testing of fire hoses is not discussed in the Branch Technical Position (APCSB) 9.5-1 (May 1976) or 9.5-1 Appendix A (August 1976). The basis for testing/replacement of interior fire hose is from NFPA 1962, Inspection, Care, and Use of Fire Hose Couplings and Testing of Fire Hose. Specifically, Section 4.3.2 requires hydro-testing not to exceed 5 years from manufacture date and every 3 years thereafter. WCGS addresses this requirement by replacing the hose every 5 years. It is more economical than the manpower cost associated with performing hydro-testing.</p>
AMPA076	B.2.1.16	<p>The LRA states that the One Time Inspection Program is a new AMP. However, in the 21 years of plant operation, WCGS must have collected information on the aging of systems and components in primary water, secondary water, lube oil and fuel oil environments as part of system surveillance tests or the maintenance program. Furthermore, as part of evaluating industry experience, WCGS may have also evaluated these systems. Provide industry and plant operating experience that could be relied on to verify the effectiveness of the Water Chemistry, Fuel Oil Chemistry, and Lubricating Oil Analysis Programs.</p>	<p>As stated in the Program Evaluation Report (PER) B2.1.16, One Time Inspection, Section 3.10, there is no operating experience that indicates that the Water Chemistry, Fuel Oil Chemistry, and Lubricating Oil Programs will not be effective in preventing aging effects during the period of extended operation. In accordance with NUREG-1801 XI.M32, element 4, one time inspections will be implemented and completed no earlier than 10 years prior to the period of extended operation.</p>

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AMPA077	B.2.1.23	The Lubricating Oil Analysis License Renewal Program Evaluation Report states that the plant's Predictive Maintenance Group reviews lubricating oil analysis results and determines the acceptability for continued service using engineering judgment. Provide documentation that shows the analyses trending performed by the Predictive Maintenance Group.	Examples of lube oil analysis results documents have been provided in the hardcopy AMP binder available at the site during the audit for the Turbine Driven Auxiliary Feedwater Pump and Safety Injection Pumps. Oil analysis results are reviewed by the predictive maintenance group to determine if alert levels have been reached or exceeded. This review checks for unusual trends.
AMPA078	B.2.1.23	Provide the basis and associated documentation for the oil sampling frequencies	<p>Lube oil sampling frequencies were initially established using a combination of EPRI guidance, equipment vendor recommendations, and the oil supplier's assessment based on equipment usage patterns. These sampling frequencies are evaluated on an ongoing basis based on plant operating experience. In most cases, these original frequencies have proven to be adequate and have not been changed. However, frequencies may be adjusted towards more frequent sampling if sample results (for example, an unexpected increase in wear particle concentration) or operating history (oil-related equipment failure) warrant. Industry benchmarking and self assessments have also been performed to evaluate the sample frequencies within the total context of all the preventive and predictive activities for the components.</p> <p>There is no formal document reflecting a basis for the sampling frequencies. Individual sampling frequencies are identified in the preventive maintenance requirements for each component.</p>
AMPA079	B.2.1.9	A review of QCP 20 518, "Visual Examination of Heat Exchangers and Piping Components," indicates that visual inspection can detect wall thinning. Explain and provide supporting documentation that show how visual inspection will be able to detect wall thinning.	QCP 20-0518 states that "Where practical, component wall thinning shall be quantified to determine the extent of condition. Depth of thinning may be determined by mechanical means or other suitable NDE methods." (Step 6.5) Visual inspection would detect wall thinning by identifying corrosion, surface or finish discontinuities, or a lack of symmetry of the component dimensions. Mechanical means or NDE methods could then be used to further quantify the degradation.
AMPA080	B.2.1.9	The Open Cycle Cooling Program description states that NDE examinations are not performed in containment coolers. Performance testing can indicate if a leak is present; however, it cannot detect an eminent leak due to wall thinning.	The relevant text from NUREG-1801 XI.M20 element 4 states: Inspections for biofouling, damaged coatings, and degraded material condition are conducted. Visual inspections are typically performed; however, nondestructive testing, such as ultrasonic testing, eddy current testing, and heat transfer capability testing, are effective methods to measure surface condition and the extent of wall thinning associated with the service water system piping and components, when determined

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		<p>Explain how wall thinning is detected and trended for this component.</p>	<p>necessary.</p> <p>The introduction to NUREG-1801 element 5 states: Inspection scope, method (e.g., visual or nondestructive examination [NDE]), and testing frequencies are in accordance with the utility commitments under NRC GL 89-13.</p> <p>Performance of the containment coolers is monitored utilizing hydraulic and thermal testing methodologies. The containment coolers are tested for hydraulic performance using the pressure drop method. The containment coolers are tested for thermal performance using the heat transfer method. Visual inspection, periodic cleaning, and NDE (ECT) are not performed on the containment coolers. ECT is not viable for the Containment Coolers due to accessibility constraints, therefore wall thinning cannot be directly measured.</p> <p>Inspection scope, method, and testing frequency are consistent with the Wolf Creek commitments identified in Wolf Creek letter ET 99-0042, Updated Response to Generic Letter 89-13 dated November 17, 1999.</p>
AMPA081	B.2.1.9	<p>Procedure AP 23L-001, Revision 2, Section 2.0, "Lake Water Systems Corrosion and Fouling Mitigation Program" and the Open Cycle Cooling License Renewal Evaluation Report indicate a difference in the components and systems that are subject to the scope of this program. Clarify the discrepancy and clearly identify which components and systems are managed under this program.</p>	<p>Procedure, AP 23L-001, "Lake Water Systems Corrosion and Fouling Mitigation Program", establishes the general requirements for implementation of and maintenance of programs which monitor the performance and structural integrity of lake water systems which provide cooling for plant components. Procedure AP 23L-001, Revision 2, Section 2.0, identifies that the procedure applies to the following systems:</p> <ul style="list-style-type: none"> - Service Water (WS & ES) - Essential Service Water (EF) - Circulating Water (CW & DA) - Fire Protection (EP & KC) <p>AMP B2.1.9 Open-Cycle Cooling Water AMP section 3.1 identifies the plant systems that receive cooling water (raw water environment) from the Essential Service Water System and Service Water Systems. AMP B2.1.9 is credited with managing the aging of components and heat exchangers that are exposed to a raw water environment in those systems. Element 1 identifies that the AMP manages aging in the following systems:</p> <ul style="list-style-type: none"> - Essential Service Water - Chemical and Volume Control (CVCS chiller supply and Return Piping) - Service Water - Essential Service Water Chemical Addition - Component Cooling Water (Component Cooling Water Heat

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			<p>Exchangers)</p> <ul style="list-style-type: none"> - Spent Fuel Pool Cooling and Cleanup (Spent Fuel Pool Make-Up Piping) - Stand-by Diesel Engine (DG Intercoolers, DG Lube Oil Coolers, and DG Jacket Water Heat Exchangers) - Auxiliary Building HVAC (CCW Pump Room Coolers, Centrifugal Charging Pump Room Coolers, Containment Spray Pump Room Coolers, Electrical Penetration Room Coolers, RHR Pump Room Coolers, and Safety Injection Pump Room Coolers) - Containment Cooling (Containment Coolers) - Control Building HVAC (Control Room A/C Unit Condensers and Class 1E Switchgear A/C Unit Condensers) - Fuel Building HVAC (Spent Fuel Pool Pump Room Cooler) - Miscellaneous Buildings HVAC (AFW Pump Room Cooler) <p>Based on comparison of the list given in the Procedure to the list given in the AMP there appears to be a discrepancy. However, while the procedure describes the scope at the system level, the AMP lists the components that the systems serve. At Wolf Creek, the components and heat exchangers are assigned to the functional system, not the cooling system (i.e., ESW and SW).</p> <p>AMP B2.1.12, Fire Water System Program provides aging management of fire protection components exposed to a raw water environment (lake water). The Circulating Water System is not within the scope of License Renewal.</p>
AMPA082	B.2.1.9	<p>The Open Cycle Cooling Program PIR No. 2002-0407 describes operating experience with de-alloying of heat exchanger tubing. The applicant credits a one time inspection in the Selective Leaching of Materials Program and committed to expand the inspection scope and to develop an inspection schedule if de-alloying is found. As a result of this operating experience described in PIR No. 2002-0407, provide the plan and schedule for these additional inspections.</p>	<p>The indications described in PIR 2002-0407 in the copper-nickel tubes were suspected to be the result of dealloying but that assumption was never verified.</p> <p>It was concluded that the degradation had not caused significant deterioration of the tube walls. The corroded areas were not significant enough to determine wall loss or tube wall thinning or if significant deterioration had taken place. The suspected dealloying shows up as a bright area on the inside of the tube walls, therefore it is easily observed. The normal oxidized coating isn't present. For these heat exchangers the identified corrosion appeared to be in the early stages (occurring within the last few years). WCGS continues to monitor the condition, and compares new test data with past data in order to help determine if dealloy conditions are causing further degradation of heat exchanger tubes.</p> <p>As a result, the Selective Leaching of Materials Program was not credited</p>

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			for any of the heat exchangers identified in the PIR. If it is eventually verified that dealloying is in fact occurring, and that the projected degradation could affect these components intended functions, the Selective Leaching of Materials Program may be credited at that time.
AMPA083	B.2.1.17	Provide additional information that demonstrates that alternative mechanical methods to hardness testing are reliable for detecting selective leaching.	<p>When selective leaching occurs in gray cast iron components, the iron is dissolved leaving behind a porous mass, consisting of graphite, voids and rust. This is known as graphitization. Additionally, selective leaching in copper alloys occurs when zinc is dissolved in the liquid solution that comes in contact with the copper alloy component. When the zinc is removed a weakened and corroded structure is left behind. This is known as dezincification. The combination of visual inspections in conjunction with mechanical methods will result in selective leaching being detected. The visual inspection will detect visible corrosion while the chipping and scraping of the mechanical methods will detect a corroded component structure. If these methods detect dezincification or graphitization then a follow up examination/evaluation will be performed. The examination/evaluation may require confirmation of selective leaching with a metallurgical evaluation (which may include a microstructure examination.)</p> <p>There are no aluminum-bronze (greater than 8% aluminum) components in the scope of license renewal at WCGS.</p>
AMPA084	B.2.1.17	LRA Section A.1.17 and the Selective Leaching Program License Renewal Evaluation Report, WCGS AMP B2.1.17 Rev 1, address "visual, mechanical methods." Clarify the meaning of this term (i.e., "visual and mechanical methods" or "visual or mechanical methods.")	<p>The term (visual, mechanical methods) as seen in LRA Section A.1.17 means "visual and mechanical methods". Please see the response to question 83 for clarification of the visual and mechanical inspection.</p> <p>LRA section A.1.17 will be amended to change "visual, mechanical methods" to "visual and mechanical methods"</p>
AMPA085	B.2.1.14	The applicant stated that no preventive action is taken for the diesel fire pump fuel tank because the internals are inaccessible. The applicant also stated that biocides and/or corrosion inhibitors have not been used to mitigate corrosion. The staff noted that since water and particulate contamination and corrosion has been detected in other WCGS fuel oil tanks, it is possible that MIC, pitting and general	<p>The diesel fire pump fuel oil tanks have similar internal material of construction and environment as the emergency fuel oil day tanks. Periodic sampling and testing for water and sediment has demonstrated that neither the fuel oil day tanks nor the diesel fire pump fuel tanks have any history, within the last ten years, of water and sediment levels exceeding the normal chemistry level of 0.05%. This demonstrates that both tanks have the same material and internal environment.</p> <p>The periodic sampling, cleaning, and visual inspection of the emergency fuel oil day tanks will act as a representative sample and ensure that significant aging is not occurring in other fuel oil day tanks. The emergency fuel oil tanks inspection results will be of value in assessing</p>

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		corrosion might be present in the diesel fire pump fuel tank as well. Undetected degradation could be progressing through the tank wall since cleaning and visual inspection has not been performed in the diesel fire pump fuel tank. The applicant indicated that operating experience for the other fuel oil tanks justifies not having to implement preventive actions. Provide additional information that justify not having to implement preventive actions such as cleaning and visual inspections on a periodic basis if alternate inspection methods such as UT are not employed.	<p>the condition of the diesel fire pump fuel oil tanks since these tanks have similar internal materials and environments.</p> <p>Any adverse condition found in the inspected emergency fuel oil day tanks will be assumed to be occurring in the emergency fuel oil day tanks and preventive actions will be taken in accordance with the WCGS corrective action program.</p> <p>One-time inspection of the bottom of the diesel driven fire pump fuel oil tank will confirm the effectiveness of this approach. LRA Sections A1.14 and B2.1.14 and LRA commitment number 6 for Fuel Oil Chemistry (RCMS 2006-203) will be amended to include a one time ultrasonic (UT) or pulsed eddy current (PEC) thickness examination on the external surface of engine driven fire pump fuel oil tank (1DO002T) to detect corrosion related wall thinning. If UT is used, the examination will be on a 4 inch grid. The examination will be performed once during the 8 years between 10 years prior to the period of extended operation and 2 years prior to the period of extended operation.</p>
AMPA086	B.2.1.14	Provide the acceptance criteria and the basis for minimum wall thickness.	The acceptance criteria and the basis for minimum wall thickness have not yet been determined. STN MT-002 inspection procedure provides for supplemental ultrasonic thickness measurements if there are indications of reduced cross sectional thickness found during the visual inspection and requires that Engineering evaluate all indication and specify required repair.
AMPA087	B.2.1.14	Clarify if microbiological activity will be monitored and biocide and corrosion inhibitors be added if reduction of thickness is discovered during UT. If not, please provide a justification.	<p>When fuel oil particulate levels equal or exceed 6 mg/L and have been verified by a second particulate analysis, the Procedure, AP 02-003, "Chemistry Specification Manual", requires a system engineer be contacted for possible corrective actions, including biological testing of fuel. Corrective actions are taken to prevent recurrence when the specified limits for fuel oil standards are exceeded or when water is drained during periodic surveillance. Additionally, when the presence of biological activity is confirmed, a biocide is added to fuel oil.</p> <p>When reduction of thickness is discovered during UT, an engineering evaluation of all indications is required. Specific corrective actions are implemented in accordance with the plant quality assurance (QA) program.</p>
AMPA088	B.2.1.14	USAR, Section 9.5.4.1.2 indicates that biocides are used to mitigate corrosion. However, the exception to the GALL Report described in preventive action program element	Biocides are not added on a routine basis. Biocides are only added when testing indicates biological activity. Per the chemistry requirements when operations removes water from the diesel storage tank during performance of either STS JE-004A or STS JE-004B, the water removed shall be tested for biological activity. Test results at 10^3 or greater

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		<p>of the Fuel Oil Chemistry Program indicates that biocides are not added on a routine basis. Provide additional information and supporting documentation related to biocide additions to diesel fuel.</p>	<p>CFU/ml, for a treated tank, or 10⁵ or greater CFU/ml, for an untreated tank, shall be cause to have operations treat the affected tank with Kathon FP 1.5. The recommended dosing level is one gallon of Kathon FP 1.5 per 10,000 gallons of fuel in the tank.</p> <p>The Emergency Diesel Generator Fuel is analyzed for particulate when received and is also tested monthly. Procedure AP 02-003, section 6.43.1 states.</p> <p>Note 1: If the value is 6 mg/L or greater, resample and verify TSS results.</p> <p>Note 2: Pull an extra liter from the bottom of the tank for possible biological testing.</p> <p>Note 3: If 6 mg/L or greater particulate is verified by a second analysis, contact System Engineering for possible corrective actions, including biological testing of fuel.</p> <p>Procedures, STS JE-004A/B, "Emergency Fuel Oil Storage Tank Water Check/Removal" directs for Operations personnel to contact Chemistry if water is detected during the monthly surveillance.</p> <p>The Diesel Fire Pump Fuel is analyzed for acceptance prior to the new fuel being offloaded into the day tank. This activity is controlled by Procedure, SYS DO-110, "Diesel Fire Pump Day Tank". Additionally, the day tank fuel is sampled every 92 days per Procedure ,STN FP-600, "Fire Pump Diesel Fuel Storage Tank".</p>
AMPA089	B.2.1.14	<p>The Fuel Oil Chemistry Program operating experience shows that corrosion has been discovered in the emergency fuel oil storage tank. Provide the frequency at which UT is performed when degradation is discovered in diesel fuel tanks.</p>	<p>Emergency Fuel Oil Tanks</p> <p>UT inspections are only required if indications of reduced cross sectional thickness is found. The frequency at which UT is performed on the Emergency Fuel Oil Tanks has not been determined because degradation, which requires a UT, has not been found.</p> <p>A visual inspection in 2002 revealed that the interior coating of one of the emergency fuel oil storage tanks was deteriorated and some rust had developed in the interior walls of the tank. An engineering evaluation determined that the failure of the interior coating of the emergency fuel oil storage tank should not result in degradation or failure of the diesel system to perform its intended functions. It was also determined that the rust identified during this inspection was an acceptable condition because it is not at a stage that could result in the component failures to perform its intended function and any degraded conditions in future inspections will be documented in a non-conformance work order. Upon the discovery of the condition of the emergency fuel oil storage tank interior coating, a biocide</p>

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			<p>was added to that tank and all of the diesel fuel in the emergency fuel oil storage tanks was subsequently replaced with new fuel. Since the discovery of the condition of the emergency fuel oil storage tank interior coating, one of the emergency fuel oil day tanks has been visually inspected, and no coating degradation was found. In 2006 both day tanks were inspected and no debris was found and no degradation of the coatings was found.</p>																																		
AMPA090	B.2.1.14	<p>Provide the acceptance criteria and the basis for all fuel quality parameters such as flash point, sulfur content, total particulate, water and sediment content, etc.</p>	<p>The acceptance criteria for the Emergency Diesel Generator Fuel and the Diesel Fire Pump Fuel are as follows. Reference Procedure, AP 02-003, "Chemistry Specification Manual" page 51 and 63.</p> <p>Emergency Diesel Generator Fuel</p> <table border="0"> <thead> <tr> <th>Parameter</th> <th>Limit</th> </tr> </thead> <tbody> <tr> <td>API gravity</td> <td>27° - 39° API</td> </tr> <tr> <td>Kinematic visc.</td> <td>1.9 <= x <= 4.1 Cst @ 40°C</td> </tr> <tr> <td>Water & Sediment</td> <td><= 0.05%</td> </tr> <tr> <td>Flash Point</td> <td>>= 51.7°C</td> </tr> <tr> <td>Particulates</td> <td><= 10 mg/l (Normal Value <5 mg/l, Supv Value <6 5 mg/l)</td> </tr> <tr> <td>Cloud Point</td> <td><= -9°C (Supv Value -13°C)</td> </tr> <tr> <td>Carbon Residue</td> <td><= 0.35%</td> </tr> <tr> <td>Ash</td> <td><= 0.01%</td> </tr> <tr> <td>Dist. Temp. @ 90% Point</td> <td>282.2°C <= x <= 338°C</td> </tr> <tr> <td>Sulfur</td> <td><= 0.5%</td> </tr> <tr> <td>Copper Corrosion</td> <td>Max. No. 3</td> </tr> <tr> <td>Cetane Number</td> <td>Min. 40 (Supv Value >= 45)</td> </tr> </tbody> </table> <p>Diesel Fire Pump Fuel</p> <table border="0"> <thead> <tr> <th>Parameter</th> <th>Limit</th> </tr> </thead> <tbody> <tr> <td>Kinematic visc.</td> <td>1.3 <= x <= 4.1 Cst @ 40°C</td> </tr> <tr> <td>Water & Sediment</td> <td><= 0.05%</td> </tr> <tr> <td>Particulates</td> <td><=10 mg/liter (supv limit <=6 mg/liter)</td> </tr> </tbody> </table> <p>WCGS uses the recommendations and methodology of D1796-83 to determine the amount of contamination due to water and sediment in diesel fuel. The testing conducted using ASTM D1796 gives quantitative results, whereas D2709 testing gives only pass-fail results; therefore, the D1796 method gives more descriptive information about the fuel oil condition than the D2709 method. WCGS uses the recommendations and methodology of the modified D2276-78 Method A for determination of</p>	Parameter	Limit	API gravity	27° - 39° API	Kinematic visc.	1.9 <= x <= 4.1 Cst @ 40°C	Water & Sediment	<= 0.05%	Flash Point	>= 51.7°C	Particulates	<= 10 mg/l (Normal Value <5 mg/l, Supv Value <6 5 mg/l)	Cloud Point	<= -9°C (Supv Value -13°C)	Carbon Residue	<= 0.35%	Ash	<= 0.01%	Dist. Temp. @ 90% Point	282.2°C <= x <= 338°C	Sulfur	<= 0.5%	Copper Corrosion	Max. No. 3	Cetane Number	Min. 40 (Supv Value >= 45)	Parameter	Limit	Kinematic visc.	1.3 <= x <= 4.1 Cst @ 40°C	Water & Sediment	<= 0.05%	Particulates	<=10 mg/liter (supv limit <=6 mg/liter)
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AMPA091	N/A	<p>Jackson:</p> <p>(1) Several of the License Renewal Program Evaluation Reports identify "Open Items" in section 5.2 of the report. The open items typically identify need (or potential need) to revise specified plant procedures or similar documents.</p> <p>Explain which processes are used to ensure that these open items are tracked and closed. Clarify if the License Renewal Program Evaluation Reports will be updated to reflect closure of these open items.</p>	<p>particulates in diesel fuel.</p> <p>The purpose of the AMP open items was to track progress of an item as information became available. AMP open items were used to identify items that might change shortly before or shortly after issue of the LRA. Significant open items were entered in one of the following Wolf Creek processes for tracking:</p> <ul style="list-style-type: none"> • Corrective Action process as a Performance Improvement Request (PIR) or Condition Report • Regulatory Commitment Management System (RCMS number assigned) <p>The License Renewal Program Evaluation Reports would be updated if the open item is completed prior to issue of the LRA annual update and the update changes the content of the WCGS evaluations for one of the AMP 10 elements.</p> <p>The following is a listing and/or status of AMP open items:</p> <p>B.2.1.1 - XI.M1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Supporting information for 3rd Interval ISI – non-significant AMP impact.</p> <p>B.2.1.3 - XI.M3 Reactor Head Closure Studs Revisions issued – no AMP impact</p> <p>B.2.1.5 - XI.M11 Nickel-Alloy Penetration Nozzles Welded To The Upper Reactor Vessel Closure Heads Of Pressurized Water Reactors Editorial change for consistency - non-significant AMP impact.</p> <p>B.2.1.8 - XI.M19 Steam Generator Tube Integrity Coordination with AMP XI.M2 Water Chemistry AMP – Water Chemistry AMP submitted with exception – no AMP impact.</p> <p>B.2.1.9 - XI.M20 Open-Cycle Cooling Water System Condition Report 2006-000489</p> <p>B.2.1.10 -XI.M21 Closed-Cycle Cooling Water System RCMS 2006-200</p> <p>B.2.1.11 - XI.M23 Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems PIR 05-3094</p>

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			<p>B.2.1.22 - XI.M38 Inspection Of Internal Surfaces In Miscellaneous Piping And Ducting Components RCMS 2006-208</p> <p>B.2.1.25 - XI.E2 Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits RCMS 2006-210</p> <p>B.2.1.27 - XI.S1 ASME Section XI, Subsection IWE One procedure changed no AMP impact – one procedure in revision</p> <p>B.2.1.32 - XI.S6 Structures Monitoring Program RCMS 2006-214 PIR 20052848</p> <p>Plant Specific - PSNI Nickel Alloy Aging Management Editorial change for consistency between procedures</p>
AMPA092	N/A	<p>Patel:</p> <p>(1) The PIR operating experience reports for several AMPs include PIRs up to 2004 only. Please provide additional PIRs issued during 2005 and 2006 pertinent to the respective AMPs.</p>	<p>PIRs through PIR 20051006 dated April 12, 2005 (in AMP B.2.1.32 Structures Monitoring) were reviewed for AMP 10 element evaluations. PIRs for the remainder of 2005 and all of 2006 were reviewed to identify PIRs that explicitly identify an aging effect or identify an AMP issue that can be attributed to managing an aging effect. Results of the review were made available during the AMP audit.</p>
AMPA111	B.2.1.21	<p>Please provide additional details to supplement the Operating Experience in the LRA for WCGS AMP B.2.1.21, Flux Thimble Tube Inspections:</p> <p>A) When was inspection in accordance with NRC IE Bulletin 88-09 first performed at WCGS?</p> <p>B) Has inspection using eddy current testing been performed on every flux thimble at every outage since such testing was first begun?</p> <p>C) The Operating Experience in the LRA states that eleven flux thimble</p>	<p>A) The first thimble tube inspection using eddy current testing (ECT) with recorded wear results was performed during Refuel 4, Spring 1990.</p> <p>B) Eddy current testing has been performed on every flux thimble at every outage since such testing was first begun.</p> <p>C) The ten thimbles replaced due to thimble wall thinning were ordered with the chrome plating and available for replacement during RF12. However, during cycle 12, after the new chrome plated thimbles had been ordered, thimble J08 developed an obstruction which would not allow the incore detector to traverse the thimble. The eleventh thimble, J08, was replaced due to the obstruction, and not due to through wall wear. Since a chrome plated thimble was not available and thimble wear was not a concern for this thimble, an available thimble of original design and manufacturing was used to replace the obstructed thimble.</p>

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		<p>tubes have been replaced and that ten were replaced with chrome plated tubes in identified wear areas which are more wear resistant. Why was the eleventh flux thimble tube not replaced with more wear resistant material in wear areas? What was the material of construction for the eleventh flux thimble tube replacement?</p> <p>D) Please provide a summary of additional operating experience from the Fall 2006 refueling outage.</p>	<p>D) All 58 thimbles were ECT inspected during Refuel 15, Fall 2006. All thimbles met acceptance criteria for an additional cycle of operation. No thimble tubes were repositioned or replaced.</p>
AMPA112	B.2.1.10	<p>B.2.1.10-3: The "monitoring and trending" element enhancement states that new periodic preventive maintenance activities will be developed to specify performing inspections of the internal surfaces when valves are disassembled for operational readiness inspections. However, the "acceptance criteria" element is not enhanced to indicate that new acceptance criteria will be developed for these new inspections. Please explain where the acceptance criteria for these new inspections will be provided.</p>	<p>As stated in Sections A1.10 and B2.1.10 of the LRA, a new periodic Preventive Maintenance activity will be developed to specify performing inspections of the internal surfaces of valve bodies and accessible piping while the valves are disassembled for operational readiness inspections. The acceptance criteria will be specified in this Preventive Maintenance activity.</p> <p>Section A1.10 of the LRA and LRA commitment number 3 for the Closed-Cycle Cooling Water System (RCMS 2006-200) will be amended to include the following statement: "The acceptance criteria will be specified in this Preventive Maintenance activity."</p> <p>Section B2.1.10 of the LRA in the Enhancement for Monitoring and Trending - Element 5, the paragraph will be amended as follows: "A new periodic preventive maintenance activity will be developed to specify performing inspections of the internal surfaces of the valve bodies and accessible piping while the valves are disassembled for operational readiness inspections to detect loss of material and fouling. The acceptance criteria will be specified in this Preventive Maintenance activity."</p>
AMPA113	B.2.1.32	Question deleted by WCGS	Question deleted by WCGS
AMPA114	B.2.1.26	<p>In WCGS-AMP-B.1.2.26, Revision 1, Section 3.10 under Operating Experience, you have stated that a review of plant operating experience history determined that water has accumulated in cable manholes. In 2004, the cable manholes for the in-</p>	<p>The evaluation of PIR 1998-1790 was based on the criteria available at that time. Since 1998 additional guidance and information has become available. Based on this information, Wolf Creek initiated a preventive maintenance (PM) program to inspect applicable manholes containing medium-voltage cables. This PM program was revised to include information from draft procedure MPE CI-004. This inspection includes removal of water, if required, visual inspection for corrosion and</p>

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		<p>scope medium voltage cables exposed to significant moisture simultaneously with significant voltage were inspected for degradation of the cable support member to water.</p> <p>However, in PIR No. 19981790, you have stated that you identified a substantial amount of water in Man-Hole 119. This manholes contain 13.8 kV cable that go to the circulation water. This manhole also does contain other in-scope of medium-voltage cables. It appears that no corrective action was taken and an evaluation was performed and concluded that cable was o.k. to be submerged. If these cables are allowed to be wet for a period of time, there is a possibility of cable degradation that can effect their safety-functions during the current and period of extended operation. Describe corrective actions taken to address water problem in manholes. Will Procedure MPE CI-004 be implement during the current and during period of extended operation?</p>	<p>degradation of cable tray supports and visual inspection for cable jacket degradation. Procedure MPE CI-004 will be implemented before the period of extended operation.</p>
AMPA115	B.2.1.26	Describe a program used to capture internal and external plant operating experience issues.	Wolf Creek's existing corrective action program captures internal and external plant operating experience issues.
AMPA118	B.2.1.36	GALL XI.E6 states that the specific type test is to be a proven test such as thermography, contact resistance testing, or other appropriate testing justify in the application. In addition, EPRI TR-104231, "Bolted Joint Maintenance & Application Guide," recommend measure contact resistance using low ohm meter to detect loose connections. In	LRA sections B2.1.36 and A1.36 will be amended to include contact resistance testing, or other appropriate testing methods for low voltage low current or low load circuit.

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		B2.1.36, you states that infrared thermography testing is used to identify loose connection. Explain how thermography is an effective method for detecting loose connections or high resistance for cable connections in low current or low load circuit where temperature rise may not be detectable.	
AMPA119	B.2.1.36	GALL XI.E6 states that the location (high temperature, high humidity) be considered for cable connection sampling. In AMP B2.1.36, you have stated that the selected sample include plant indoor air environment. Explain how aging effect of loose connections and/or high resistance due to corrosion are not a potential aging require management for electrical cable connections in outdoor environment.	LRA section B2.1.36 will be amended to include electrical cable connections in outdoor air.
AMPA120	B.2.1.26	ISG-2 states, in part, that restoration of offsite power paths be included in the scope of license renewal. These paths typically consist of the first breaker in the switchyard to the start up transformers to the safety-related 4.16 kV buses. The scope of your Inaccessible Medium Voltage Cables not Subject to 10 CFR 50.49 EQ requirements only include underground cables from disconnection switch 13-23 to ESF transformer to 4.16 kV safety buses. It does not include underground cables from secondary side of transformer No. 7 to disconnection switch 13-23 which provide the remaining part for SBO restoration. When underground cables are subject to water tree, no matter how many redundancy path it have,	<p>The WCGS per ISG-2 includes in the scope of License Renewal two paths of SBO restoration power. The WCGS connections to the switchyard are through disconnects not circuit breakers. One path is from disconnect 345-163 via overhead lines to the station start-up transformer. The other path is from disconnects 13-21 or 13-23 via underground cable to the station ESF transformer. This configuration conforms to the requirement of Criterion 17 that states, "the onsite electrical distribution system shall be supplied by two physically independent circuits designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions."</p> <p>The entire WCGS plant system portion of the SBO restoration power system is within the scope of license renewal. This is consistent with ISG-2 Staff Position which states "Consistent with the requirements specified in 10 CFR 54.4(a)(3) and 10 CFR 50.63(a)(1), the plant system portion of the offsite power system should be included within the scope of license renewal". The 345KV switchyard system equipment beyond disconnect 345-163 and the 13.8KV switchyard system equipment beyond disconnects 13-21 and 13-23 including the 13.8KV switchgear, circuit breaker 13-48, transformers No4/No 5/No. 7 and the underground cables</p>

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		<p>common mode failures may occur to all underground cables. If the underground cables connecting disconnect switch 13.23 are not managed/tested, provide your technical justification how you satisfy with ISG-2 to ensure that SBO restoration paths are maintained during the extended period of operation.</p>	<p>are part of the offsite transmission system (grid) and are not part of the plant system portion of offsite power and therefore not within the scope of License Renewal. Westar Energy is the owner of the Wolf Creek switchyard and is responsible for switchyard equipment design, operations and maintenance.</p>
AMPA121	B.2.1.9	<p>During review of operating experience, it was noted that in PIR 20020407 there was degradation discovered during visual examination that appeared to be resulting from de-alloying in the Emergency Diesel Generator Heat Exchanger train "A" tubing (copper alloy C44300). Subsequent eddy current testing revealed multiple degradation indications. Metallurgical evaluation of the tubing showed no de-alloying. Most indications were identified as erosion-corrosion. One indication was a stress corrosion crack. SCC of copper alloys is usually associated with ammonia or polluted waters. Please provide the details of augmented inspection, trending, mitigation etc. resulting from this degradation incident.</p>	<p>There was one indication in the Emergency Diesel Generator Intercooler Heat Exchanger that was called a stress corrosion crack. It was an axial crack. The exact initiation mechanism could not be conclusively established since the original ID surface was lost due to flow-assisted corrosion.</p> <p>On-going corrective actions include preventive maintenance to eddy current test, analyze the data, and take corrective actions for any tubes that do not meet acceptance criteria.</p> <p>Also, the Emergency Diesel Generator Heat Exchangers are being replaced with AL6X tubing material. The Intercooler Heat Exchangers were replaced during RF15, in 2006. The Lube Oil Coolers are targeted for replacement in RF16, in 2008 or during a planned maintenance outage at power. The Jacket Water Coolers are targeted for replacement in RF18, in 2011 or during a planned maintenance outage at power.</p>
AMPA122	B.2.1.9	<p>During review of operating experience, it was noted that in PIR 20040688 that there was an increase in leakage trend in the Electrical Pen Room cooler, the RHR Pump "A" cooler, the CCP "A" Room cooler and the Containment Air "D" Cooler. What was the cause of the leaks? What actions are being taken to address the increased leak trend?</p>	<p>About half of the room cooler leaks are the result of an isolated pit going through wall in the tubing. In the remaining half of the leaks, we encountered through wall pitting combined with some flow erosion in the H-bend areas. Tubes with deep through wall pitting were allowed to remain in service because past Eddy Current acceptance criteria allowed it. The Eddy Current acceptance criteria was changed and past ECT data was reviewed to select room coolers for replacement. The RHR pump "A" cooler leak caused a lot of unavailability time and Room Coolers were declared a Maintenance Rule (a)(1) issue. Corrective action consists of changing out degraded coolers. Out of sixteen total room coolers, eleven have been replaced, three are scheduled to be replaced by RF16 (2008)</p>

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			<p>and the remaining two are being targeted for replacement by the end of 2008. New cooler bundles are procured with AL6XN tube materials.</p> <p>On-going actions include preventive maintenance to eddy current test, analyze the data, and take corrective actions for any tubes that do not meet acceptance criteria.</p> <p>Containment Air "D" Cooler The failure mechanism of pitting and erosion for the tubes and U-bends is assumed to be consistent with other copper nickel tube bundles in the room coolers. This assumption is based on same materials and same water source being used in the containment coolers and the room coolers. Apparent cause is planned for the tube bundles being replaced in RF16 (2008). Future corrective actions will be based on the apparent cause.</p> <p>Due to the configuration of these coolers, eddy current testing is not possible. Flow and dP and heat transfer capability are periodically verified per Wolf Creek's commitment to Generic Letter 89-13. Any leakage is detected early by continuous monitoring leak detection systems.</p>
AMPA123		<p>There is no aging management program to manage the aging of coatings. Please justify not having an aging management program for coatings. The failure of coatings could result in aging effects for the steel shell in containment. The failure of coatings could also result in the failure of safety systems to perform their intended functions (for instance, safety injection).</p>	<p>Coatings of the Wolf Creek Reactor Building steel liner are not within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), or 10 CFR 54.4(a)(3). Coatings of the Wolf Creek Reactor Building steel liner do not have an intended function.</p> <p>LRA Table 3.5.2-1 notes that consistent with GALL line item II.A1-11, loss of material due to general, pitting, and crevice corrosion of the Wolf Creek Reactor Building steel liner is managed by AMP B2.1.27, ASME Section XI Subsection IWE. The coated surfaces of the Wolf Creek Reactor Building liner are visually examined by AMP B2.1.27, ASME Section XI Subsection IWE as an indication of the condition of the steel surfaces underneath the coating. Reactor Building ASME Code Section XI, IWE 3510.2, "Visual Examination of Coated and Non-coated areas," states that "The condition of the inspected area is acceptable if there is no evidence of damage or degradation which exceeds the visual acceptance criteria specified by the Owner." Detailed visual examination acceptance criteria at Wolf Creek identifies the following conditions as rejectable for coated surfaces:</p> <ul style="list-style-type: none"> - Cracking - Flaking - Blistering - Peeling - Discoloration

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			<ul style="list-style-type: none"> - Deformation - Other signs of distress <p>All rejectable indications require initiation of a Non-Conformance Report (NCR) and evaluation in accordance with the WCGS corrective action process.</p> <p>The effects of containment debris on the intended function of the RHR & Containment Spray sump screens is being addressed by industry efforts to resolve GSI-191. The contribution of coatings to the containment debris is event driven and is not related to aging.</p>
AMPA124	B.3.1	<p>In elements "Detection of aging effects" and "corrective action program", the application states that action levels of the Fatigue Management Program will be enhanced to ensure that... Please explain what you mean by action levels.</p>	<p>The WCGS Fatigue Management Program provides for periodic evaluation (once per operating cycle) of fatigue usage and cycle count tracking of critical thermal and pressure transients to verify that design limits on fatigue usage will not be exceeded. The program will be enhanced to include action limits (values for accrued transient cycles and calculated cumulative fatigue usage (CUF) that require initiation of corrective actions) and definition of acceptable corrective actions that may be implemented to assure that ASME Code limits on CUF are not exceeded. For locations identified in NUREG/CR-6260, action limits will be based on fatigue usage calculated including the environmental effects of the reactor coolant.</p> <p>1. Cycle Count Action Limits: A limit will be established that requires corrective action when the cycle count for any of the critical thermal and pressure transients is projected to reach a high percentage (e.g., 90%) of the design specified number of cycles before the end of the next operating cycle. Appropriated corrective actions if this limit is reached include:</p> <ul style="list-style-type: none"> a. Review of fatigue usage calculations to determine whether the transient in question contributes significantly to CUF or to identify the components and analyses (e.g., HELB screening calculations and LBB crack propagation) that are affected by the transient in question. b. Evaluation of remaining margins on CUF based on cycle based or stress based CUF calculations using the fatigue monitoring program software. c. Redefinition of the specified number of cycles (e.g., by reducing specified numbers of cycles for other transients and using the margin to increase the allowed number of cycles for the transient that is approaching its specified number of cycles). <p>2. Cumulative Fatigue Usage Action Limits:</p>

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			<p>A limit will be established that requires corrective action when calculated CUF (from cycle based or stress based monitoring) for any monitored location is projected to reach 1.0 within the next 2 or 3 operating cycles. Appropriate corrective actions if this limit is reached include those listed below. These corrective actions are equally applicable to WCGS NUREG/CR-6260 locations with consideration of the environmental effects of reactor coolant.</p> <ul style="list-style-type: none"> a. Determine whether the scope of the monitoring program must be enlarged to include additional affected reactor coolant pressure boundary locations, to ensure that other locations do not approach design limits without an appropriate action. b. Enhance fatigue monitoring to confirm continued conformance to the code limit. c. Repair the component. d. Replace the component. e. Perform a more rigorous analysis of the component to demonstrate that the design code limit will not be exceeded. f. Alter plant operation to reduce the rate of fatigue usage accumulation rate. g. Perform a flaw tolerance evaluation and impose component-specific inspections. <p>LRA Chapter 4.3.1, Appendix A.2.1, and Appendix B.3.1 will be amended to conform to this response.</p>
AMPA125	B.3.1	In elements "detection of aging effects" and "corrective action program", the application states that corrective actions of the Fatigue Management program will be enhanced to ensure that... Please clarify where these corrective actions are identified?	The response to AMPA124 describes action limits that will be incorporated into the fatigue monitoring aging management program and specifies the corrective actions that are appropriate in response to each action limit.
AMPA126	B.2.1.22	Please explain why the pertinent operating experience related to internal surface inspections of piping and ducting components that may have been performed during the plant maintenance and surveillance activities is not included in the operating experience section of the LRA? Currently, no operating	<p>The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is a new program. Therefore no programmatic operating experience has been gained.</p> <p>The Inspection of Internal Surfaces Program will be implemented via existing predictive maintenance, preventive maintenance, surveillance testing and periodic testing work order tasks. Such tasks have been in place at Wolf Creek since the plant began operation. These activities have proven effective at maintaining the material condition of systems,</p>

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		experience has been included.	<p>structures, and components and detecting unsatisfactory conditions. A review of PIRs from 1995 to 2006 for HVAC components in the scope of license renewal and within the scope of this AMP did not identify any loss of intended functions due to loss of material in HVAC ducting, nor hardening and loss of strength associated with elastomers used in HVAC flexible connections. Operating experience from mechanical components in other mechanical systems (non-HVAC) within the scope of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting components AMP will be reviewed during implementation of the AMP prior to the period of extended operation.</p> <p>System Engineers review operating experience for possible impact to the equipment in their systems. The basis for parameters monitored and inspection intervals is based on vendor recommendations, historical performance, and industry wide operating experience. The new program will be reviewed to account for industry and station operating experience.</p>
AMPA127	B.2.1.22	NUREG-1801, element 6 recommends that indications of various corrosion mechanisms or fouling that would impact component intended function are reported and will require further evaluation. Does the WCGS aging management program include monitoring of fouling? If not, please justify why this is not an exception to element 6 of NUREG-1801?	<p>Monitoring for fouling was not included because it was not identified as an aging effect for any component currently in scope for this AMP. The LRA will be amended to reflect this fact and to eliminate any concern that this might be an exception.</p> <p>The first sentence of LRA Section A1.22 will be amended to state: "The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program manages cracking, fouling, loss of material and hardening - loss of strength."</p> <p>LRA Section B2.1.22 will be amended as follows: The first sentence changed and a second sentence added to state: "The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program manages cracking, fouling, loss of material and hardening - loss of strength. Fouling has not been identified as an aging effect in any component currently in scope for this AMP."</p> <p>The Wolf Creek comparison to NUREG-1801 under section 2.1 of WCGS-AMP-B2.1.22 is amended as follows: The first sentence changed and a second sentence added to state, "The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program manages cracking, fouling, loss of material and hardening - loss of strength. Fouling has not been identified as an aging effect in any component currently in scope for this AMP."</p>
AMPA128	B.3.2	Provide examples of operating experiences showing that the	The WCNOG Preventative Maintenance (PM) program manages age related replacement / refurbishment of equipment and surveillance

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		<p>Environmental Qualification (EQ) of Electrical Components Program has succeeded in managing aging degradation in a timely manner. Also, describe any corrective action or program enhancement as a result of these operating experiences.</p>	<p>activities based on a schedule dictated by the WCNOE EQSD-III document. Any unexpected adverse conditions that are identified during operational and maintenance activities in regards to aging degradation issues would be managed through the plant's corrective action program or via work orders generated and assigned to the EQ Program Engineer. The EQ Program Engineer also reviews and evaluates industry operating experience and other sources of information (such as Scientec's monthly newsletter) for applicability to WCNOE, and where necessary implements the necessary corrective actions.</p> <p>No examples of age related failures of EQ equipment could be identified for the life of the plant. There are several examples of industry operating experience that were reviewed that required no action due to already sufficient requirements, such as identified in PIR 2002-2756 ("Normally Energized ASCO Solenoid Valves (SOV) That Are in Service Beyond Their Qualified Life") and ITIP 5025 (generated for NRC Regulatory Issue Summary 2003-09 "Environmental Qualification of Low-Voltage Instrumentation and Control Cables"). There is reasonable assurance that the existing WCNOE EQ Program is sufficient, and able to manage age related issues prior to actual equipment failures.</p>
AMPA129	B.3.2	<p>Provide a sample of electrical components in EQ master list including EQWP J-361A for high-range radiation monitor cables. These cable were excluded from the scope of AMP B2.1.25. Also, provide a sample of maintenance performed on some EQ electrical components to maintain their qualified life.</p>	<p>Provided hard copy of pages 65 and 66 of the EQ master document EQSD-II (Revision 25). This document identifies how Wolf Creek classifies the components in regards to the accident conditions along with room locations and environments. These two pages include the high radiation monitor components (J-361A) along with some other components.</p> <p>Provided the first five pages of EQSD-III (Revision 8) that shows the replacement/refurbishment schedule for the age restricted parts of valve ABHV0011. In addition to these sheets four pages from a sample Work Order (WO 98-128835-001) are provided. This WO performed the EQ maintenance activity for valve ABHV0011. These pages identify the WO number and the scope of the work.</p>
AMPA130	B.3.2	<p>Under "acceptance criteria" element, you have stated that an enhancement will be made to be consistent with GALL's acceptance criteria element. Specially, the enhancement states that the program documents will be enhanced to describe methods that may be used for qualified life</p>	<p>LRA sections A2.3 and B3.2 and LRA commitment number 22 for Environmental Qualification of Electrical Components (RCMS 2006-219) will be amended to remove the stated enhancement. The current WCGS EQ program methods will be used for qualified life evaluation in the period of extended operation.</p>

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		<p>evaluation for the period of extended operation. Describe methods that may be used for qualified life evaluation for the period of extended operation. How these methods are consistent with GALL's AMP X.E1 under the "acceptance criteria" element.</p>	
AMPA131	B.3.1	<p>In LRA Section B3.1, the applicant credited an enhancement "confirmation process" program element stating that "The WCGS Metal Fatigue of Reactor Coolant Pressure Boundary program will be enhanced to invoke Appendix B procedural and record requirements." However, the enhancement description provided in Commitment No. 21, item 4, is different. Clarify this discrepancy and justify the differences between the enhancement description in the LRA and the one in the commitment list.</p>	<p>WCGS will supplement LRA Appendix A2.1 and Appendix B3.1 as described in the response to AMPA124.</p> <p>Commitment No. 21, Item 1 corresponds to the first bullet of LRA Appendix A2.1 and to the first paragraph of LRA Appendix B3.1 under "Enhancements," "Detection of Aging Effects, Element 4, and Corrective Actions - Element 7."</p> <p>Commitment No. 21, Item 2 corresponds to the second bullet of LRA Appendix A2.1 and to the second and third paragraphs of LRA Appendix B3.1 under "Enhancements," "Detection of Aging Effects, Element 4, and Corrective Actions - Element 7."</p> <p>Commitment No. 21, Item 3 corresponds to the third bullet of LRA Appendix A2.1 and to the fourth paragraph of LRA Appendix B3.1 under "Enhancements," "Detection of Aging Effects, Element 4, and Corrective Actions - Element 7."</p> <p>Commitment No. 21, Item 4, "10 CFR 50 Appendix B procedural and record requirements," corresponds to the fourth bullet of LRA Appendix A2.1 and to LRA Appendix B3.1, "Enhancements," "Confirmation Process - Element 8."</p> <p>These are consistent.</p> <p>The sentence following Commitment No. 21, Item 4 should be a separate paragraph:</p> <p>"Prior to the period of extended operation, changes in available monitoring technology or in the analyses themselves may permit different action limits and action statements, or may re-define the program features and actions required to address the fatigue time-limited aging analyses (TLAAs)"</p> <p>This sentence anticipates future events that may require adjustments to</p>

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			<p>the program. It applies to the first three of these items, not to Item 4. WCGS does not anticipate any future events that would affect the commitment to 10 CFR 50 Appendix B procedural and record requirements.</p>
AMPA132	B.2.1.21	<p>WCGS' letter WM 89-0015, "Response to NRC Bulletin 88-09," dated January 18, 1989, states, in part, "The thimble tube inspection program requires that of [sic] any tubes with wall loss of 60 percent or more be removed from service."</p> <p>The Flux Thimble Tube Inspection Program implementing procedure RXE 03-006 states "Any thimbles with wear in an active location greater than 60 percent through wall or projected to be greater than 60 percent before next outage should be repositioned.." It also states, "Any thimbles with wear greater than 80 percent through wall or projected to be greater than 80 percent before next outage shall be capped, or equivalent, and considered for future replacement."</p> <p>GALL AMP XI.M37, under "acceptance criteria" program element, states "Acceptance criteria different from those previously documented in NRC acceptance letters for the applicant's response to Bulletin 88-09 and amendments thereto should be justified."</p> <p>a. Provide a technical justification for the change from 60 percent to 80 percent through wall wear criteria for removing a flux thimble tube from service.</p>	<p>a. WCAP-12866, Bottom Mounted Instrumentation Flux Thimble Wear, was used to justify the change from 60% to 80% through wall wear criteria at Wolf Creek for removing flux thimble tubes from service. Appendix A of WCAP-12866 provides the results of pressure testing and a finite element analysis and determined the maximum allowable wall loss. Based on the Westinghouse tests results, it was conservatively determined that a flux thimble can remain in service with up to 80% wall loss. The 80% wall loss acceptance criteria will maintain the structural and functional integrity of the flux thimble tubes and the flux thimble tubes can remain in service up to 80% wall loss.</p> <p>It is noted that Wolf Creek procedures address corrective actions at 60% indicated wall loss to prevent further through wall loss by wear.</p> <p>b. Based on the Westinghouse tests, eddy current data over estimates the depth of actual wear scars. Using eddy current thimble wear data to predict wear will result in very conservative predictions of wall loss. Although the WCAP states, " it is not necessary to add additional uncertainty margin to the eddy current wall loss indications....," Wolf Creek uses an uncertainty margin of 5% for conservatism.</p> <p>Conservatism of the methodology for projecting wear for the following operating cycles is confirmed by WCAP test data that exhibits an exponentially decreasing curve of flux thimble wall loss versus operating time.</p>

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		b. Address whether the 80 percent acceptance criteria includes the allowances for uncertainties that are recommended in the GALL Report and whether the methodology for projecting wear for the following operating cycles is conservative.	
AMPA133	B.2.1.21	Provide the limit on maximum number of flux thimble tubes that can be removed from service. Explain what is the basis for that limit.	<p>The maximum number of thimbles that can be removed from service can be as high as 14 as specified in the basis for Technical Requirement (TR) 3.3.10 Movable Incore Detectors:</p> <p>"TR 3.3.10 specifies that the Movable Incore Detection System shall be OPERABLE. OPERABILITY with greater than or equal to 75% of the detector thimbles, a minimum of two detector thimbles per core quadrant, and sufficient movable detectors, drive, and readout equipment to map these thimbles ensures that measurements obtained from use of this system accurately represent the spatial neutron flux distribution of the core when the system is used for the specified activities"</p> <p>Although TR 3.3.10 permits as many as 14 (25%) of the 58 thimbles to be out of service, Wolf Creek strives to maintain all thimbles operable and takes timely corrective actions to return inoperable thimbles to service as soon as practical. In Refuel 11 Wolf Creek had to cap two thimbles. Those two thimbles and nine additional thimbles were replaced in the next refueling outage (Refuel 12) per WO 00-221918-000. That was the only time to date that thimbles were removed from service (capped) due to fretting wear.</p>
AMPA134	B.2.1.4	Within the Boric Acid Corrosion Monitoring Program, WCGS is treating fasteners too difficult to remove for engaged thread inspection as "seized" in the context of being interference fit or staked to prevent backing out. This practice is based on an interpretation of a footnote on page 4 of NRC inspected in place." As a result, the engaged threads of certain stuck fasteners designed to be removable, but are difficult to remove, are not being inspected as required by ASME Section XI.	<p>This question originated from a review of WCGS OE. PIR 1997-3658 problem initiation stated that within the Boric Acid Corrosion (BAC) Monitoring Program, WCNOG is treating fasteners too difficult to remove for engaged thread inspection as "seized" in the context of being interference fit or staked to prevent backing out. This practice is based on an interpretation of a footnote on page 4 of NRC IE Bulletin 82-02, which states "fasteners seized or designated with interference fit may be inspected in place." As a result, the engaged threads of certain stuck fasteners designed to be removable, but are too difficult to remove, are not being inspected as required by ASME Section XI.</p> <p>The PIR resolution is as follows: "The statement within this PIR which implies that this is an ASME Section XI inspection is incorrect. The inspection was required by NRC Bulletin 82-02 which stated that Section XI acceptance criteria was to be utilized.</p>

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		<p>Are these fasteners being inspected in place? If not, has WCGS requested relief from the Section XI requirement?</p>	<p>The Bulletin also stated that fasteners which were seized or interference fit could be inspected in place. This indicates that either excessive force would be required to remove the fastener (seized) or the fastener was designed to be difficult to remove or back out (interference fit). In either case this allowance is technically justified when considering that a borated water path into the fastener threads would have to begin at an exposed surface. Also, boric acid corrosion needs oxygen which also is not present in sufficient quantities internal to a seized fastener. Both the borated water path and oxygen supply would be present at the exposed surface of the fastener thus the Bulletin was correct in allowing such fasteners to be inspected in place."</p> <p>Based on the above, seized or interference fit fasteners are inspected in place, and no ASME relief is required since the BAC AMP inspection is not a code requirement.</p>

Wolf Creek AMR Audit Questions and Responses

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AMRA001	3.1	<p>LRA Table 3.1.1, item 3.1.1.63, states that this line is consistent with the GALL Report with AMP exceptions.</p> <p>This line corresponds to GALL Report, Volume 1, Table 1, item 63, which identifies the Inservice Inspection (IWB, IWC, and IWD) as the AMP. This line includes GALL Report Volume 2, item IV.B2-26, lower internal assembly, radial keys and clevis inserts made of stainless steel.</p> <p>LRA Table 3.1.2-1 does not appear to include any lower internals assembly components that references to LRA Table 3.1.1, item 3.1.1.63; and it does not include any line corresponding to GALL Report, Volume 2, item IV.B2-26. However, It does include a line (page 3.1-62) for "lower internals assembly (clevis insert bolts, radial keys, clevis inserts)" made of nickel alloys, where the aging effect is identified as "loss of material" and the AMP is identified as the Water Chemistry Program.</p> <p>For the components "lower internals assembly (clevis insert bolts, radial keys, clevis inserts):</p> <p>a. Explain whether the components are subject to aging effect of loss of material due to wear? Provide a justification for your conclusion.</p>	<p>(a) The clevis insert bolts, radial keys and the clevis inserts are subject to aging effect of loss of material due to wear. LRA Table 3.1.2-1 will be amended to include a new line for clevis insert bolts, radial keys, clevis inserts made of nickel alloy in a reactor coolant environment with an aging effect of loss of material that is managed by the ASME Section XI ISI AMP. The new line will reference GALL Report, Volume 2, item IV.B2-34.</p> <p>(b) The line in LRA page 3.1-62 for "lower internals assembly (clevis insert bolts, radial keys, clevis inserts)" of nickel alloys with the aging effect of "loss of material" is due to the aging mechanism of pitting and crevice corrosion. Based on GALL Report, Volume 2, item IV.B2-32, the Water Chemistry Program would provide adequate aging management for pitting and crevice corrosion. The new line to be added for item (a) above will rely on the ASME Section XI ISI AMP to manage the aging effect due to wear.</p> <p>(c) The components are included within the scope of the ISI Program under examination Category of B-N-2 and B-N-3. The clevis, clevis insert, and clevis insert bolts are inspected every 10 years under Category of B-N-2 and the radial keys attached to the core barrel are inspected under Category of B-N-3 with same interval.</p> <p>(d) There is no operating experience with regard to failure of these components that has been identified by WCGS. They have been inspected three times, once at initial installation, and twice since then. No wear has been detected.</p>

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		<p>b. Justify why the Water Chemistry Program by itself would provide adequate aging management for those components.</p> <p>c. Explain if the components are included within the scope of the ISI Program. If so, clarify under what examination category are they included?</p> <p>d. Describe any site-specific or industry operating experience with regard to failure of these components that has been identified by WCGS.</p>	
AMRA002	3.1	<p>GALL Report, Volume 2, Item IV.A2-5, lists a vessel flange leak detection line and recommends a plant-specific AMP be evaluated. This line references to GALL, Volume 1, Table 1, Line 23. LRA Table 3.1.1, item 3.1.1.23, identifies the ASME Section XI ISI, Subsections IWB, IWC and IWD, and Water Chemistry as the plant-specific AMPs. However, item 3.1.1.23 only identifies the following components: "RV penetrations (instrument tubes (top head), high pressure conduits)"</p> <p>a. Explain why the LRA does not include a vessel flange leak detection line in this item</p> <p>b. Explain the function and configuration of the components identified as "high pressure conduits"</p>	<p>(a) The vessel flange leak detection line is addressed by the RV Closure Head (O-Ring Leak Monitoring Tubes) in LRA Table 2.3.1-1. It is made of nickel alloy, thus is not associated with GALL Report, Volume 2, Item IV.A2-5, which is based on the material of stainless steel. The RV Closure Head (O-Ring Leak Monitoring Tubes) is evaluated with GALL Report, Volume 2, Items IV.A2-14 and IV.A2-18 (see LRA Table 3.1.2-1, page 3.1-43), and is referenced to LRA Table 3.1.1, items 3.1.1.83 and items 3.1.1.65, respectively.</p> <p>(b) High Pressure Conduits are the guide tubes that enclose the flux thimble tubes from the bottom of the vessel and provide a pressure boundary function for the reactor coolant system.</p>
AMRA003	3.1	<p>GALL Report, Volume 2, items IV.A2-6, IV.A2-7 and IV.A2-8, lists three aging effects for the "control rod drive head penetration - flange</p>	<p>Based on the description of the reactor vessel closure head in USAR 5.3.3.1 and CRDM housing in USAR 3.9(N).4.1, the lower portion of latch housings are seal-welded to the vessel closure head adapters. GALL Report, Volume 2, items IV.A2-6, IV.A2-7 and IV.A2-8, for the "control rod</p>

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		<p>bolting" and identifies the AMP as XI.M18, "Bolting Integrity." However, comparable line items have not been found in LRA Table 3.1.2-1:</p> <p>a. Explain why comparable line items for control rod drive head penetration - flange bolting is not included in LRA Table 3.1.2-1.</p> <p>b. If there are comparable line items for control rod drive head penetration - flange bolting, please identify the material, environment, aging effect(s) and AMP for these components at WCGS.</p>	<p>drive head penetration - flange bolting" are not applicable to WCGS.</p>
AMRA004	3.1	<p>GALL Report, Volume 2, item IV.A2-10, provides the MEAP combination for component "control rod drive head penetration - pressure housing." However, the LRA does not contain a comparable line.</p> <p>a. Explain why WCGS does not have a line comparable to the one in the GALL Report.</p>	<p>GALL Report, Volume 2, item IV.A2-10, is a line for material of CASS with aging effect of cracking. The following components of the "control rod drive head penetration - pressure housing" are not CASS and IV.A2-10 is not applicable for "control rod drive head penetration - pressure housing" of WCGS:</p> <p>(1) Latch Housing, Travel Housing, CRDM Cap and CRDM Flange are made of SA-182, F304 stainless steel. The corresponding GALL lines for the applicable aging effects are IV.A2-11 and IV.A2-14.</p> <p>(2) CRDM Tubes are made of nickel alloy and the corresponding GALL lines for the applicable aging effects are IV.A2-9 and IV.A2-14.</p>
AMRA005	3.1	<p>GALL Section XI.M12, "Thermal Aging Embrittlement of CASS," states that for low molybdenum content (0.5 wt percent max.) steels, only static-cast steels with more than 20 percent ferrite are potentially susceptible to thermal embrittlement. The discussion in LRA Table 3.1.1, line 3.1.1.57, states that this aging effect is not applicable at WCGS because the molybdenum and ferrite values are below the threshold for thermal aging embrittlement.</p>	<p>The WCGS reactor coolant loop pipe fittings are static castings. The WCGS reactor coolant loop straight piping sections are centrifugal casings.</p> <p>The actual maximum reported molybdenum and ferrite values for static cast CASS Class 1 piping at WCGS are 0.35% molybdenum and 19.5% ferrite. WCGS Certified Material Test Reports supporting the limiting values of molybdenum and ferrite content of CASS Class 1 piping at WCGS were made available for NRC review during the site visit.</p>

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		<p>The LRA states (Note 2, page 3.1-94) that WCGS Certified Material Test Reports support the limiting values of molybdenum and ferrite content of CASS Class 1 piping at WCGS.</p> <p>What are the actual maximum reported molybdenum and ferrite values for static cast CASS Class 1 piping at WCGS? Provide a copy of the supporting documentation for review during the site visit.</p>	
AMRA006	3.1	<p>Lines in LRA Table 3.1.2-2 for piping and valves made of stainless steel in a demineralized water (treated water) environment have an aging effect of "loss of material due to pitting and crevice corrosion" and the effect is managed by the Water Chemistry and One-Time Inspection Programs. These lines appear to have the same component and MEAP combinations as GALL Report, line V.C-4. However, LRA Table 3.1.2-2 refers to Note G indicating that the environment is not in the GALL Report for this component and material.</p> <p>Explain why Note G was used for these lines in the LRA.</p>	<p>The Lines in LRA Table 3.1.2-2 for piping and valves made of stainless steel in a demineralized water in LRA Table 3.1.2-2 (the last line in page 3.1-76 and the last line in page 3.1-91) will be amended with the new lines using GALL Report, line V.C-4 and the Note changed to D.</p>
AMRA007	3.1	<p>LRA Table 3.1.2-2 does not appear to include a line that is comparable to GALL Report, Volume 2, item IV.C2-21, which includes pressurizer instrumentation penetrations, heater sheaths and sleeves, etc.</p> <p>a. Explain why WCGS does not have a line comparable to the one in the GALL Report.</p>	<p>(a) The material of the subject components are not nickel alloy or nickel alloy cladding. Thus GALL Report, Volume 2, item IV.C2-21 is not applicable to these components of WCGS.</p> <p>(b) The subject components of WCGS are within the scope of license renewal and are evaluated in LRA Table 3.1.2-2 from page 3.1-81(the last line) to page 3.1-85 (the first line).</p>

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		<p>b. If the components listed in GALL Report, Volume 2, item IV.C2-21, are within the scope of license renewal at WCGS, please provide the AMR results.</p>	
AMRA008	3.1	<p>Provide a technical or CLB reference to support the following statement from LRA Table 3.1.1, item 3.1.1.80: "WCGS reactor vessel internals are forged stainless steel not cast austenitic stainless steel."</p>	<p>LRA Table 3.1.1, item 3.1.1.80 is a roll-up summary for the applicable GALL lines IV.B2-21 and IV.B2-37.</p> <p>GALL lines IV.B2-21 is for aging evaluation of (1) Lower Support Casting and (2) Lower Support Plate Columns. The lower support assembly of WCGS is equipped with Lower Support Forging instead of Lower Support Casting. Based on Design Specification for Nuclear Reactor Internals, M-703-00207, the Lower Support Forging and the Lower Support Plate Columns are designed with 300 series stainless steel. Thus the GALL line IV.B2-21 is not applicable to WCGS.</p> <p>GALL lines IV.B2-37 is for aging evaluation of Upper Support Columns. Based on Design Specification for Nuclear Reactor Internals, M-703-00207, the Upper Support Plate Columns are designed with 300 series stainless steel. Thus the GALL line IV.B2-37 is not applicable to WCGS.</p> <p>In summary, CASS is not applicable to the subject components and the GALL lines IV.B2-21 and IV.B2-37 are not applicable to WCGS. Thus, LRA Table 3.1.1, item 3.1.1.80 is also not applicable to WCGS.</p>
AMRA009	3.1	<p>LRA Table 3.1.2-2 has several components (corresponding to GALL Report, Volume 2, item IV.C2-22) associated with the pressurizer relief tank which references LRA Table 3.1.1, item 3.1.1-68. These components can be divided into two categories with respect to AMPs identified in the LRA. One category is those that are managed by the ASME Section XI ISI, Subsections IWB, IWC and IWD and the Water Chemistry Programs. These components reference Note D, and the AMPs (with exceptions) are consistent with the GALL Report recommendations. The other</p>	<p>The affected items of LRA Table 3.1.2-2 regarding non-ASME components of Stainless Steel in the environment of Treated Borated Water for aging effect of Cracking are:</p> <ol style="list-style-type: none"> (1) Component Type of Flow Element with Intended Function of LBS in page 3.1-73. (2) Component Type of Piping with Intended Function of SIA and LBS in page 3.1-78. (3) Component Type of Pressurizer Relief Tank with Intended Function of SIA in page 3.1-79. (4) Component Type of Rupture Disc with Intended Function of LBS in page 3.1-88. (5) Component Type of Thermowell with Intended Function of LBS in page 3.1-90. (6) Component Type of Valve with Intended Function of LBS and SIA in page 3.1-93.

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		<p>category of components are those that are managed by the Water Chemistry Program only. These components reference Notes E and 1. Note 1 explains that these are not ASME Section XI components; therefore, the ASME Section XI ISI AMP will not be used.</p> <p>a. For the components managed only by the Water Chemistry Program, provide a technical justification to support that the Water Chemistry Program by itself provides adequate aging management during the period of extended operation.</p> <p>b. Provide a justification for not performing an inspection to confirm the effectiveness of the Water Chemistry Program to manage the aging effect of cracking.</p>	<p>For these components, the aging evaluation for the aging effect of Cracking due to SCC will use GALL line V.D1-31 which relies on Water Chemistry for managing the aging effect of Cracking.</p> <p>LRA Table 3.1.2-2 will be amended to use GALL line V.D1-31 for the above listed lines. The Standard Note will be "B" instead of "E" and Plant Specific Note #1 following Table 3.1.2-2 will be changed to indicate #1 is not used, without renumbering other Specific Notes.</p>
AMRA010	3.1	<p>GALL Report, item IV.C2-11, is described as "piping, piping components, and piping elements." The comparable line item in LRA Table 3.1.2-2 (page 3.1-74) is "heat exchanger tube side (HX # 3, 4, 6, 7, 8)" for the reactor coolant pump bearing heat exchangers.</p> <p>a. Justify the reference to Note D for this line item.</p>	<p>(a) As defined at the end of LRA Table 3.1.2-2, Note D is used for the cases where the subject components are different from the subject GALL item, but consistent with the GALL item for material, environment, and aging effect. AMP takes some exceptions to GALL AMP. Copper-Nickel is a type of copper alloy, thus the material, environment and aging effect are consistent with GALL IV.C2-11. The AMP of Closed-Cycle Cooling Water System is credited for aging management. According to LRA Section B2.1.10, WCGS AMP of Closed-Cycle Cooling Water System is consistent with exception to GALL, Section XI.M21, "Closed-Cycle Cooling Water." Since heat exchanger tube is not included in the definition of "piping, piping components, and piping elements" in GALL Table IX.B, Standard Note D is selected.</p>
AMRA011	3.1	<p>In the LRA tables 3.1.2-X, there is no component line item similar to GALL Report, item IV.C2-12. The discussion in LRA Table 3.1.1.56 states that WCGS does not have copper alloy components (more than 15 percent Zn) exposed to closed cycle cooling water within the scope</p>	<p>(a) LRA Table 3.1.1 items 54 and 56 are the summary of aging evaluation regarding GALL items IV.C2-11 and IV.C2-12 for copper alloy components in Reactor Coolant system. It does not include all in-scope copper alloy components exposed to closed cycle cooling water at WCGS. There are copper alloy components of Auxiliary System addressed in LRA Section 3.3 that are exposed to closed cycle cooling water. They are summarized in LRA Table 3.3.1, items 51 and 84.</p>

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		<p>of license renewal.</p> <p>a. Confirm that the components that references to LRA, item 3.1.1.54, are the only in-scope copper alloy components exposed to closed cycle cooling water at WCGS.</p> <p>b. Explain, what documentation supports a determination that the copper alloy in these components contains less than 15 percent Zn.</p>	<p>(b) The subject copper alloy components in Reactor Coolant system are cooling tubes for RCP pump motor air cooling and bearing oil cooling. The material is copper-nickel of ASME Spec SB-111-706 and SB-171-706. The reference of the material is QR-54586 (Quality Release/Certification of Compliance).</p>
AMRA012	3.1	<p>GALL Report, item IV.C2-18, identifies the ASME Section XI ISI, Subsections IWB, IWC and IWD and Water Chemistry Programs as the applicable AMPs for pressurizer components. The LRA is consistent with the GALL Report in that it identifies the same AMPs. However, the GALL Report includes a further discussion stating that the area of the weld metal between the surge nozzle and the lower vessel head is periodically inspected as part of the ISI program.</p> <p>a. Confirm if WCGS performs periodic inspection in the area of the weld metal between the surge nozzle and the lower vessel head as part of the ISI program.</p> <p>b. Clarify, what is the periodicity of the inspection.</p> <p>c. Clarify what is the ASME Section XI examination category for this component.</p> <p>d. Discuss any adverse indications found in the area of the described</p>	<p>(a) (b) As described in WCGS USAR, Section 5.4.10.4, the weld between the surge nozzle to the pressurizer lower head is designed and constructed to present a smooth transition surface for ultrasonic inspection to implement the requirements of the ISI program. As demonstrated by the third interval ISI program plan, WCRE-16, Table 1 of BB system, the UT inspection for the subject weld is scheduled for once for every ISI plan interval, i.e., once every 10 years.</p> <p>[c] The ISI category for the inspection of the weld between the surge nozzle to the pressurizer lower head is B-D, Code Item number of B3.110.</p> <p>(d) No indications were found in the inspection of Refueling Outage 13 (the second ISI interval). The inspection results were available during the site audit.</p>

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		weld and any repairs made or flaw indications found and evaluated as acceptable.	
AMRA013	3.1	LRA Table 3.1.2-3 (page 3.1-101), contains two lines corresponding to GALL Report, item IV.D1-6. The component descriptions and MEAP combinations for both lines are identical and are consistent with the GALL Report. The only differences between the lines are the intended functions and the Notes. Explain why Note B is used for one of these lines and Note D is used with the second of these two lines.	<p>The subject items in LRA Table 3.1.2-3 (page 3.1-101) will be amended to clarify that (1) the item with a function of DF is the Primary Channel Divider Plate. It matches the component description of GALL Report, item IV.D1-6. With the exception of the "Water Chemistry" AMP, a Standard Note of "B" is used. (2) the item with a function of NSRS is the SG Primary Nozzle Closure Ring. It does not match the component description of GALL Report, item IV.D1-6. With the exception of the "Water Chemistry" AMP, a Standard Note of "D" is used.</p> <p>The last item in page 3.1-100 with a function of PB also needs to be amended to clarify that component is the Tubesheet - Primary Face.</p>
AMRA014	3.1	<p>The LRA does not include a comparable line to GALL Report, item IV.D1-16, "steam generator structure - tube support lattice bars." This is discussed in LRA Table 3.1.1, item 3.1.1.78, which states that "WCGS steam generator does not contain lattice bars, so the applicable NUREG-1801 line was not used."</p> <p>In addition, the LRA does not include a component similar to that in GALL Report, item IV.D1-17, "steam generator structure - tube support plate."</p> <p>a. Clarify if the WCGS steam generators include the lattice support bars identified in the GALL Report. If so, what are those components, and where are the AMR results discussed in the LRA.</p> <p>b. Clarify if the WCGS steam generators include a component comparable to GALL Report, item</p>	<p>(a) The steam generator of WCGS is a Westinghouse Model F design. There are no lattice support bars identified in WCGS USAR, the design specification, M-711-0011, or the stress analysis, M-711-0008.</p> <p>(b) WCGS steam generators include a component comparable to GALL Report, item IV.D1-17, "steam generator structure - tube support plate" and is addressed in LRA Table 3.1.2-3, page 3.1-108. The material is stainless steel instead of carbon steel used in GALL Report, item IV.D1-17. This issue of ligament cracking was identified in Supplement 1 to NRC IN 96-09 and applicable to the plants with carbon steel support plates. WCGS steam generator tube support plate is made of stainless steel, thus ligament cracking is not an applicable aging effect.</p>

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		IV.D1-17, "steam generator structure - tube support plate," that might be subject to the aging effect of ligament cracking due to corrosion.	
AMRA015	3.1	<p>In the LRA Table 3.1.2-3, page 3.1-97, there are two line items corresponding to GALL Report, item IV.D1-26, "steam generator feed ring made of carbon steel," with internal and external environments of "secondary water" for which the aging effect is wall thinning. The GALL Report recommends a plant-specific AMP be evaluated for this component, material, environment and aging effect combination. The AMPs listed in the LRA for these lines are the Steam Generator Tube Integrity and Water Chemistry Programs. The Notes associated with these lines are E and 1. Note 1 states, "Feedring wall thinning was described in NRC IN 91-19. This aging has been detected only in certain CE System 80 Steam Generators. The WCGS steam generators are Westinghouse Model F. No plant specific experience at WCGS or other units with Model F steam generators suggests wall thinning of the Model F is occurring. Therefore WCGS has determined this condition is not applicable and no further action is needed."</p> <p>It is not clear whether WCGS is crediting the listed AMPs for managing the aging effect of wall thinning in the components during the period of extended operation. If the AMPs are being credited, then Note A would seem appropriate</p>	<p>The AMPs of "Steam Generator Tube Integrity and Water Chemistry Programs" are credited for managing the aging effect of wall thinning of the feedrings. As indicated in LRA Section 3.1.2.2.14, the AMPs are conservatively credited to manage wall thinning of feedrings although wall thinning is not applicable to Model F steam generators.</p> <p>To clarify, the Plant Specific Note 1 for LRA Table 3.1.2-3 will be amended to indicate "no further evaluation is recommended" instead of "no further action is required" at the end of the statements.</p> <p>The Steam Generator Tube Integrity and Water Chemistry Programs are sufficient to manage the aging effect of wall thinning in the steam generator feed ring during the period of extended operation based on GALL item IV.D1-16, which credits the AMPs of the Steam Generator Tube Integrity and Water Chemistry Programs to manage the aging effect of wall thinning for the same material and environment,</p>

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		<p>rather than Note 1. If the AMPs are not being credited, then it is not clear why they are listed on the applicable lines in LRA Table 3.1.2-3.</p> <p>Explain why the Steam Generator Tube Integrity and Water Chemistry Programs are sufficient to manage the aging effect of wall thinning in the steam generator feed ring during the period of extended operation. Please justify your response.</p>	
AMRA016	3.1	<p>LRA Section 3.1.2.2.16.1 states that control rod drive mechanism and pressurizer components are stainless steel [not nickel alloy] for WCGS and; therefore, no additional commitments or further evaluation are required.</p> <p>a. LRA Section 3.1.2.2.16.1 is titled "steam generator heads, tube sheets, and welds made or clad with stainless steel." Explain why control rod drive mechanisms and pressurizer components are discussed in this subsection.</p> <p>b. Provide technical or CLB documentation that supports the LRA statement that the control rod drive mechanism and pressurizer components are stainless steel. Please have a copy or summary of that documentation for review at the site.</p>	<p>(a) Based on items #34 and #35 of NUREG-1800, Table 3.1-1, Further Evaluation recommended in NUREG-1800, subsection 3.1.2.2.16.1 is addressed in items #34 and #35 of LRA Table 3.1.1. The details are provided in LRA Section 3.1.2.2.16.1. Item #35 is applicable to once-through steam generator only. Pressurizer components are not involved in either item #34 or #35 of LRA Table 3.1.1. To clarify, LRA Section 3.1.2.2.16.1 will be amended:</p> <p>(1) The title of LRA Section 3.1.2.2.16.1 will read "Cracking on steam generator heads, tube sheets, control rod drive head penetration pressure housings and welds."</p> <p>(2) The statement will read "These control rod drive mechanism housings are stainless steel for WCGS, therefore no additional commitments or further evaluation is required."</p> <p>(3) Add the statement of "WCGS has a recirculating steam generator, not a once-through steam generator, so the further evaluation for steam generator components is not applicable to WCGS."</p> <p>(b) A copy of CLB document regarding CRDM housing was available during site audit.</p>
AMRA017	3.2	<p>LRA Table 3.2.2-2 designates Note G for stainless steel piping, valves, and tanks in the containment spray system because the environment is not in the GALL Report for this component and material.</p>	<p>a.) According to WCGS system flow drawings, the maximum temperature that the stainless steel containment spray system components exposed to a sodium hydroxide environment would experience is 125 F.</p> <p>b.) An internet search of the Hendrix Group Corrosion and Materials Technology Site lists stainless steel as a common material for use up to</p>

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		<p>a. Provide the temperature range of operation for these components.</p> <p>b. Provide references that indicate industry applications where there are no considerations for aging</p> <p>FollowupQuestion: Provide source documents to substantiate max temp stainless steel in EN system is 125F for components.</p> <p>a. Exposed to sodium hydroxide b. Internet search or Hendrix Ground corrosion & Materials lists stainless steel as a common material for use up to 200F and 50% W NaOH. c. Evaluation of WCGS stainless steel components in EN system exposed to sodium hydroxide is consistent with VC summer LRA, Table 3.2-2, item 5.</p>	<p>200F and 50%w NaOH. The aging effect and AMP were conservatively assigned. The WCGS stainless steel containment spray components exposed to a sodium hydroxide environment were evaluated consistent with the Virgil C. Summer license renewal application Table 3.2-2, AMR Item 5 and associated SER (NUREG-1787).</p> <p>Follow up response:</p> <p>a) Piping Class Summary sheets for system EN (HPCI) show that the piping design temperature is 125 F. Piping normal operating temperature is listed as 100 F. The Tank Data Sheet for the Containment Spray Additive Tank (plant tag TEN01), indicates that the normal tank operating temperature is 120 F.</p> <p>b) Hendrix corrosion and material data was provided at the site audit. Internet links to the pertinent data are: http://www.hghouston.com/naoh_tbl.html http://www.hghouston.com/naoh.html</p> <p>c) VC Summer LRA Table 3.2-2 was provided at the site audit.</p>
AMRA018	3.2	<p>The GALL Report, Section V.D1, does not include any nickel alloy components. The applicant credits the Water Chemistry Program for managing loss of material caused by pitting and crevice corrosion. The Water Chemistry Program effectively manages aging effect of loss of material of nickel alloys in treated borated water only when there is not any stagnant flow. Accumulators typically have low flow; therefore, additional action may be necessary to verify that long term corrosion is not occurring. Explain what additional provisions WCGS will be taken to ensure that corrosion is not slowly progressing.</p>	<p>Accumulator tank nickel alloy components in a treated borated water environment, require aging management of cracking and loss of material. The loss of material aging effect will be managed by the Water Chemistry AMP. The cracking aging effect will be managed by the Water Chemistry AMP augmented by the plant specific Nickel Alloys AMP. The plant specific nickel alloy AMP periodically inspects the accumulator tank nickel alloy components.</p> <p>Follow up response:</p> <p>The Water Chemistry AMP will be augmented by the One-Time Inspection AMP for verification that loss of material is not occurring in accumulator tank nickel-alloy components. LRA Table 3.2.2-10 will be amended to include the One-Time Inspection AMP in addition to the Water Chemistry AMP for managing the aging effect of loss of material. As a result, the One-Time Inspection program will include a one-time inspection of selected accumulator tank nickel-alloy components at susceptible locations.</p>

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		<p>Followup Question: The water chemistry AMP provides verification of the lack of LOM through the OTI program. However, the OTI AMP applicability does not provide for inspection of nickel-based alloys in treated borated water in the high pressure injection system. What actions are taken to verify that LOM is not occurring on the inside of nickel-based alloy components?</p>	
AMRA019	3.3	<p>LRA Table 3.3.1, item 3.3.1.07, lists stainless steel non regenerative heat exchanger components exposed to treated borated water greater than 60C (greater than 140F). In the discussion column, the LRA states that "this line item is not applicable. Other available applicable NUREG 1801 lines were used." Clarify if this means that WCGS does not have any non regenerative heat exchangers exposed to treated borated water greater than 60C (greater than 140F).</p>	<p>The Letdown, Excess Letdown and Seal Water heat exchangers are exposed to treated borated water greater than 140⁰ F (tube-side) and Component Cooling Water (shell-side). The shell-side is managed by the Closed-Cycle Cooling Water Program using item number 3.3.1.46. The tube-side is managed by Water Chemistry and One-Time inspection Programs using item number 3.3.1.08. The Closed-Cycle Cooling Water Program (B2.1.10) includes eddy current testing for heat exchanger shell-side components exposed to Component Cooling Water. Radiation monitors are installed in each train of the Component Cooling Water System and alarm when abnormal radioactivity levels are detected. Heat exchanger outlet temperature of the heat exchangers are not typically monitored, this was noted as a program exception to the Closed-Cycle Cooling Water Program.</p> <p>The LRA item number 3.3.1.07 discussion column will be amended to read the following:</p> <p>"Not applicable. The Letdown, Excess Letdown and Seal Water heat exchangers are exposed to treated borated water greater than 140 F (tube-side) and Component Cooling Water (shell-side). The shell-side is managed by the Closed-Cycle Cooling Water Program using item number 3.3.1.46. The tube-side is managed by Water Chemistry and One-Time inspection Programs using item number 3.3.1.08. The Closed-Cycle Cooling Water Program (B2.1.10) includes eddy current testing for heat exchanger shell-side components exposed to Component Cooling Water. Radiation monitors are installed in each train of the Component Cooling Water System and alarm when abnormal radioactivity levels are detected. Heat exchanger outlet temperature of the heat exchangers are not typically monitored, this was noted as a program exception to the Closed-Cycle Cooling Water Program."</p>

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AMRA020	3.3	LRA Table 3.3.1, item 3.3.1.10, lists high strength steel closure bolting exposed to air with steam or water leakage. Clarify what is the material of the closure bolting used in high pressure pumps in the chemical and volume control system.	The high pressure pumps associated with the Chemical and Volume Control System are the Boric Acid Transfer Pumps, Normal Charging Pump, Centrifugal Charging Pumps, and Boron Injection Makeup Pump. Bolting for these pumps is stainless steel grades ASTM A564 Gr. 630 and ASTM A194, Gr. 6.
AMRA021	3.3	LRA Table 3.3.1, item 3.3.1.46, lists stainless steel and stainless clad steel piping, piping components, piping elements, and heat exchanger components exposed to closed cycle cooling water greater than 60C (greater than 140F). The Closed Cycle Cooling Water System Program is credited for managing the aging effect of cracking due to SCC. One of the implementing procedures referenced in this program is QCP-20-518, "Visual Examination of Heat Exchangers and Piping Components." However, it is not clear how the use of this procedure will manage cracking as in the definition section of this document, cracking is included under general corrosion. Please clarify.	<p>The Closed Cycle Cooling Water System Program is credited for managing the aging effect of cracking due to SCC. QCP-20-518 is a visual inspection procedure and prescribes visual examination requirements for the detection of cracking (and other indications). The procedure documents "as-found" conditions, provides trend data to engineering, and where practical, creates video or photographic records of the examination. Unacceptable conditions such as cracks are documented through the corrective action program. The corrective action program would assess the components condition and any aging effects would be evaluated.</p> <p>QCP-20-518 will be revised to define cracking, provide additional guidance for detection of cracking and specific acceptance criteria relating to "as-found" cracking. A new commitment for this procedure revision was added to the License Renewal Application list of regulatory commitments.</p>
AMRA022	3.3	LRA Table 3.3.1, item 3.3.1.53, lists steel compressed air system piping, piping components, and piping elements exposed to condensation (internal). The LRA states that the 10 CFR 50 Appendix J Program is credited in lieu of the Compressed Air Monitoring Program recommended in the GALL Report to manage the aging effect of loss of material due to general corrosion for containment isolation piping and valves. The 10 CFR 50 Appendix J Program only ensures that the	<p>The piping in question is service air containment penetration piping and components on License Renewal Boundary Drawing LR-WCGS-KA-M-12KA02 (D-6). The containment isolation piping is safety-related but is attached to non-safety related structural integrity attached (SIA) piping.</p> <p>WCGS containment isolation valve testing test procedures pressurize the entire safety-related containment isolation piping section. Not only is isolation valve seat leakage tested but the entire pressure boundary is tested. The safety-related piping and valves are in-scope for pressure boundary. 10 CFR 50 Appendix J Program testing of containment isolation piping and valves provides a positive means for detection of loss of pressure boundary integrity intended function.</p> <p>The LRA will be amended to add AMP XI.M38 (Inspection of Internal</p>

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		<p>containment isolation valve does not leak through the seat and performs the containment isolation function. The visual inspection performed in this AMP only detects aging in the external surface, not in the internal surface, of piping and valves. Please explain how loss of material on the inside surface of piping and valves will be detected. (This item applies to LRA Table 3.3.2.6, compressed air system, for containment isolation piping and valves).</p>	<p>Surfaces in Miscellaneous Piping and Ducting Components) for loss of material inspection of the service air containment penetration piping internal surfaces. Credit will be taken for both the 10 CFR 50 Appendix J Program testing and AMP XI.M38 internal inspection.</p>
AMRA023	3.3	<p>LRA Table 3.3.1, item 3.3.1.68, states that this line is consistent with the GALL Report except that a different AMP is credited to manage steel piping, piping components, and piping elements with internal surfaces exposed to raw water. The LRA states that the Fire Water System Program will be credited in conjunction with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging effects. This corresponds to several line items in LRA Table 3.3.2-14 for the fire protection system for which Note E is referenced.</p> <p>Explain how these two programs are used in conjunction to manage these aging effects.</p>	<p>The Fire Water System program manages loss of material for water-based fire protection systems. Periodic hydrant inspections, fire main flushing, sprinkler inspections, and flow tests considering National Fire Protection Association (NFPA) codes and standards ensure that the water-based fire protection systems are capable of performing their intended functions. The Fire Water System program conducts an air or water flow test through each open head spray/sprinkler nozzle to verify that each open head spray/sprinkler nozzle is unobstructed. The Fire Water System program tests a representative sample of fire protection sprinkler heads or replaces those that have been in service for 50 years, using the guidance of NFPA 25 2002 Edition, and tests at 10 year intervals thereafter during the period of extended operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner.</p> <p>Visual inspections evaluating wall thickness to identify evidence of loss of material due to corrosion, ensuring against catastrophic failure, are covered by the aging management program XI.M38 "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components". The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP manages cracking, loss of material and hardening - loss of strength for components whose internal inspections are not covered by other aging management programs. Thus, the Fire Water System program internal visual inspections are covered by the Internal Inspection program. Other inspections such as, fire detection and suppression testing and maintenance, yard fire hydrant inspections and flushing, powerblock fire hose testing, hose station gasket inspections and sprinkler/spray nozzle inspections are covered by the Fire Protection program.</p>

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			Internal visual inspections will be conducted during periodic maintenance, surveillance testing and corrective maintenance to the fire protection system components in the program.
AMRA024	3.3	In LRA Table 3.3.2-1, fuel storage and handling system, the applicant credited the Structures Monitoring Program to manage the aging effect of loss of material for carbon steel new fuel racks in a plant indoor air - external environment. This AMP references implementing procedure AI 23M-007; however, the procedure does not specifically identify new fuel racks in the component or structure list. Identify where are the new fuel racks listed as within the scope of the Structures Monitoring Program.	WCGS carbon steel fuel racks are evaluated as structural steel, consistent with NUREG-1801 line VII.A1-1. The scope of AI 23M-007 applies to structures, passive components and civil engineering features in-scope for the Maintenance Rule and additional structures and components in-scope for License Renewal. Although the new fuel racks are not specifically listed in the procedure, the carbon steel new fuel racks are included with procedure AI 23M-007 Attachment C, Fuel Building structural steel components.
AMRA025	3.3	In LRA Table 3.3.2-2, fuel pool cooling and cleanup system, the applicant credited the Closed Cycle Cooling Water System Program to manage the aging effects of loss of material and reduction of heat transfer for piping, thermowell, valves, and heat exchanger components in a closed cycle cooling water internal and external environment. However, the fuel pool cooling and cleanup system is not included within the scope of the Closed Cycle Cooling Water System Program. Please clarify.	<p>The component cooling water system provides closed cycle cooling water to the fuel pool cooling and cleanup system. According to the WCGS Strategic Closed Cooling Water Chemistry Plan, "The component cooling water systems (CCWs), A and B systems, are closed loop systems designed to remove heat from various plant components during plant operation, plant cool-down and during post accident conditions." The component cooling water system in the scope of the Closed Cycle Cooling Water System AMP and the associated WCGS Strategic Closed Cycle Cooling Water Chemistry Plan refer to all components that receive component cooling water.</p> <p>The Closed Cycle Cooling Water System AMP will be used to manage fuel pool cooling and cleanup system components within the scope of license renewal that receive closed cycle cooling water from the component cooling water system.</p> <p>A STARS License Renewal Project Change Tracking Form (PCTF-0179) was created to revise the 10 element review for AMP B2.1.10 as follows: The program is credited with managing the aging of components that are exposed to closed cycle cooling water. (Reference: Strategic Closed Cycle Cooling Water Chemistry Plan, Sections 2.0, 7.0, 8.0, 9.0, and 12.0):</p> <ul style="list-style-type: none"> - Component Cooling Water (CCW) - Emergency Diesel Engine (EDE) Cooling Water System - Plant Heating *

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			<ul style="list-style-type: none"> - Central Chilled Water System * - Miscellaneous Buildings HVAC *, ** - Fuel Building HVAC *, ** - Control Building HVAC *, ** - Auxiliary Building HVAC *, ** - Containment Purge HVAC *, ** - Reactor Coolant System - Chemical & Volume Control System - Fuel Pool Cooling and Cleanup System - Residual Heat Removal System - High Pressure Coolant Injection System - Central Chilled Water System* - Liquid Radwaste System - Nuclear Sampling System
AMRA026	3.3	<p>In LRA Table 3.3.2-7, chemical and volume control system, the applicant credited the Closed Cycle Cooling Water System Program to manage the aging effects of loss of material, reduction of heat transfer and cracking for several stainless steel components in a closed cycle cooling water internal and external environment. However, the chemical and volume control system is not included within the scope of the Closed Cycle Cooling Water System Program. Please clarify.</p>	<p>The component cooling water system provides closed cycle cooling water to the chemical and volume control system. According to the WCGS Strategic Closed Cooling Water Chemistry Plan, "The component cooling water systems (CCWs), A and B systems, are closed loop systems designed to remove heat from various plant components during plant operation, plant cool-down and during post accident conditions." The component cooling water system in the scope of the Closed Cycle Cooling Water System AMP and the associated WCGS Strategic Closed Cycle Cooling Water Chemistry Plan refer to all components that receive component cooling water.</p> <p>The Closed Cycle Cooling Water System AMP will be used to manage chemical and volume control system components within the scope of license renewal that receive closed cycle cooling water from the component cooling water system.</p> <p>A STARS License Renewal Project Change Tracking Form (PCTF-0179) was created to revise the 10 element review for AMP B2.1.10 as follows: The program is credited with managing the aging of components that are exposed to closed cycle cooling water. (Reference: Strategic Closed Cycle Cooling Water Chemistry Plan, Sections 2.0, 7.0, 8.0, 9.0, and 12.0):</p> <ul style="list-style-type: none"> - Component Cooling Water (CCW) - Emergency Diesel Engine (EDE) Cooling Water System - Plant Heating * - Central Chilled Water System * - Miscellaneous Buildings HVAC *, ** - Fuel Building HVAC *, **

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			<ul style="list-style-type: none"> - Control Building HVAC *, ** - Auxiliary Building HVAC *, ** - Containment Purge HVAC *, ** - Reactor Coolant System - Chemical & Volume Control System - Fuel Pool Cooling and Cleanup System - Residual Heat Removal System - High Pressure Coolant Injection System - Central Chilled Water System* - Liquid Radwaste System - Nuclear Sampling System
AMRA027	3.3	<p>In LRA Table 3.3.2-7, chemical and volume control system, the applicant referenced Note I for stainless steel heat exchanger components in an internal environment of treated borated water and has also referenced a GALL Report, Volume 2 item, and a Table 1 item. However, Note I is not defined at the legend of Table 3.3.2.7. Since Note I implies that this line item is not consistent with the GALL Report, please clarify why a GALL Report, Volume 2 item, and a Table 1 item is referenced for these Notes.</p>	<p>Note I: Aging effect in NUREG-1801 for this component, material and environment combination is not applicable.</p> <p>No vessel, tank, pump, or heat exchanger designs at WCGS are supported by TLAAs as defined in 10 CFR 54.3 except ASME Class 1 components and the Class 2 portions of the steam generators. The design of this WCGS component is therefore not supported by TLAAs.</p> <p>The LRA Table 3.3.2-7 will be amended as follows:</p> <p>Delete TLAAs Line with component type of Heat Exchanger (HX # 45, 46, 47, 49, 51, 52, 53, 54, 55, 6, 57, 58, 59, 60, 61, 62, 63, 64, 65, 66, 67, 68) and Notes I and 7.</p>
AMRA028	3.3	<p>In LRA Table 3.3.2-7, chemical and volume control system, the applicant referenced Notes G and 1, which implies that these items are not consistent with the GALL Report, for an MEAP combination of copper alloy (brass copper less than 85 percent) in an external environment of plant indoor air with no aging effects and no AMP credited. However, in other tables the applicant references Note A for the same MEAP combination.</p> <p>For example: a. In LRA Table 3.3.2-14, this</p>	<p>LRA Table 3.3.2-7 will be amended to reference Note A and GALL Report Item VIII.I-2.</p> <p>LRA Table 3.3.2-16 will be amended to reference Note A and GALL Report Item VIII.I-2.</p> <p>LRA Table 3.3.2-14 remains unchanged and currently references Note A and GALL Report Item VIII.I-2. The existing note definitions will be amended to update and make consistent.</p>

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		<p>combination references Note A and GALL Report, item VIII.I 2</p> <p>b. In LRA Table 3.3.2-7, this combination references Note 1 stating that "This non NUREG-1801 line was used to account for copper alloy in plant indoor air (external) in the chemical and volume control system. See precedent of NUREG 1801, line VIII.I 2."</p> <p>c. In LRA Table 3.3.2-16, this combination references Notes G and 3</p> <p>Although it is the same combination, the staff notes that the definition of Note 3 in LRA Table 3.3.2-16 is different than the definition of Note 1 in LRA Table 3.3.2-7. Also, the staff notes that the applicant uses different notes (A or G) for the same combination. If the same MEAP combination is applicable, explain why Note A is not used consistently. Clarify this discrepancy and justify your response.</p>	
AMRA029	3.3	<p>In LRA Table 3.3.2-9, control building HVAC system, the applicant referenced Note I for elastomer flex connectors in an environment of plant indoor air and ventilation atmosphere and referenced a GALL Report item and a Table 1 item. Since Note I implies that this line item is not consistent with the GALL report, clarify why a GALL Report item and a Table 1 item is referenced.</p>	<p>Flexible connectors for the Control Building HVAC system are synthetic elastomers (neoprene) in an environment of air-indoor-uncontrolled. The general thermal environment in the Control Building is maintained less than 95 F.</p> <p>The aging effect listed for GALL line VII.F1-7 is hardening and loss of strength / elastomer degradation. NUREG-1801 Chapter IX.C, defines Elastomers as "materials rubber, EPT, EPDM, PTFE, ETFE, viton, vitril, neoprene, and silicone elastomer. Hardening and loss of strength of elastomers can be induced by elevated temperature (over about 95°F (35°C), and additional aging factors such as exposure to ozone, oxidation, and radiation." NUREG-1801, Chapter IX.D, has a definition for Air-indoor-uncontrolled (>95 F). This definition discusses the temperature threshold for elastomer thermal aging, "If ambient is <95°F, then any resultant thermal aging of organic materials can be considered to be insignificant, over the 60-yr period of interest." The EPRI guideline, Non-</p>

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			<p>Class 1 Mechanical Implementation Guideline and Mechanical Tools, Appendix D Section 2.1.8 states in part that, "synthetic rubbers are not affected by ozone and are typically much more resistant to sunlight (or other forms of ultraviolet radiation)."</p> <p>NUREG-1801 GALL line VII.F1-7 specifies hardening and loss of strength as the aging mechanism. However the GALL also states that if the temperature threshold is not exceeded, that elastomer thermal aging is insignificant. The EPRI guide states that synthetic rubbers such as neoprene are not affected by ozone, sunlight or other forms of ultraviolet radiation. Thus, hardening and loss of strength of the Control Building HVAC flexible connectors is not expected.</p> <p>The LRA will be amended as follows:</p> <ul style="list-style-type: none"> - LRA Table 3.3.2-9, Control Building HVAC System, Component Type "Flexible Connectors" will be amended to eliminate reference to GALL line VII.F1-7. A Non-GALL row will be created. The Non-GALL row will have the identical material, environment, aging effect and AMP as currently listed for the flexible connectors. Notation will also be included describing why these elastomers are not subject to hardening (similar to discussion above). - LRA Table 3.3.1 item 3.3.1.11 will be amended to remove discussion of the exception to NUREG-1801 for Control Building Flexible Connectors.
AMRA030	3.3	<p>In LRA Table 3.3.2-10, fuel building HVAC system, the applicant referenced Note A for carbon steel adsorber in an internal environment of ventilation atmosphere; however, a GALL Report item and a Table 1 item were not referenced. Note A implies that this line is consistent with the GALL Report. Therefore, if the line is consistent with the GALL Report, identify the GALL Report and the Table 1 items. If the line is not consistent, clarify the discrepancy.</p>	<p>Note A was inadvertently used. Unlike other carbon steel ventilation components, it is unlikely that an adsorber would have condensation as an internal environment. The adsorbers 1st stage contain moisture separators to ensure moisture does not impregnate the charcoal filters. Therefore, a separate plant specific aging evaluation was created.</p> <p>The LRA will be amended as follows:</p> <p>LRA Table 3.3.2-10, Fuel Building HVAC System, Component Type "Adsorber" will be amended to use note "G" in lieu of note "A". A plant specific note will be added that states, "GALL row VII.F2-3 has an internal environment of condensation. Unlike other carbon steel ventilation components, it is unlikely that an adsorber would have condensation as an internal environment. The adsorbers 1st stage contain moisture separators to ensure moisture does not impregnate the charcoal filters. Therefore, a separate (non condensation) row needed to be created since the ventilation atmosphere is dry and no aging effects are expected."</p>
AMRA031	3.3	<p>In LRA Table 3.3.2-16, emergency diesel engine system, the applicant referenced Note D for copper alloy</p>	<p>Note D was incorrectly used. GALL does not consider reduction of heat transfer/fouling for copper alloy heat exchanger tubes in lubricating oil. Therefore, a separate plant specific aging evaluation was created.</p>

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		<p>heat exchanger component in an external environment of lube oil; however, a GALL Report item and a Table 1 item were not referenced. Note D implies that this line is consistent with the GALL Report. Therefore, if the line is consistent with the GALL Report, identify the GALL Report and the Table 1 items. If the line is not consistent, clarify the discrepancy.</p>	<p>The LRA will be amended as follows: LRA Table 3.3.2-16, Emergency Diesel Engine System, Component Type "Heat Exchanger Tube Side HX#150) will be amended to use note "H,4" in lieu of note "D,4". Plant specific note #4 already exists for this row. No changes to the existing plant specific note are required.</p>
AMRA032	3.3	<p>In LRA Table 3.3.2-16, emergency diesel engine system, the applicant referenced Note A for stainless steel valve in an internal environment of wetted gas; however, a GALL Report item and a Table 1 item were not referenced. Note A implies that this line is consistent with the GALL Report. Therefore, if the line is consistent with the GALL Report, identify the GALL Report and the Table 1 items. If the line is not consistent, clarify the discrepancy.</p>	<p>Note A was incorrectly assigned to this non-GALL aging evaluation line.</p> <p>The LRA will be amended as follows: LRA Table 3.3.2-16, Emergency Diesel Engine System, Component Type "Valve", environment "wetted gas" will be amended to use note "G,1" in lieu of note "A,1". Plant specific note #1 already exists for this row. No changes to the existing plant specific note are required.</p>
AMRA033	3.3	<p>In LRA Table 3.3.2-16, emergency diesel engine system, the applicant credited the Open Cycle Cooling Water System Program to manage the aging effect of loss of material for carbon steel piping and valves in an environment of raw water. However, the Open Cycle Cooling Water System Program includes standby diesel engine within the scope of the program, but not the emergency diesel engine system. Clarify if the standby diesel engine is considered as part of the emergency diesel engine system. Explain why the emergency diesel engine system is not included within the scope of this program.</p>	<p>The Emergency Diesel Engine System is also known as the Standby Diesel Engine System. LRA Section 2.3.3.16 states this fact in the first sentence of the system description.</p>

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AMRA034	3.3	In LRA Table 3.3.2-17, floor and equipment drains system, the applicant credited the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program in lieu of the Lubricating Oil Analysis and One Time Inspection Programs to manage loss of material in stainless steel tanks. The bottom of the tanks are very susceptible to this aging effect. Clarify if the credited program will include wall thickness measurement of the bottom of the tanks.	<p>The stainless steel reactor coolant pump drain tank receives lubricating oil leakage from the reactor coolant pump motors. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP will manage the loss of material due to pitting and crevice corrosion for stainless steel components in a lubricating oil environment by visual inspections for loss of material. If internal inspections detect loss of material, the aging would be resolved via the WCGS corrective action program.</p> <p>See also AMRA038.</p>																
AMRA035	3.3	In LRA Tables 3.3.2-8, 3.3.2-9, 3.3.2-10, and 3.3.2-12 reference Note E and GALL Report item VII.F2-14 for copper and copper nickel heat exchanger tube side component. These tables also credit the External Surfaces Monitoring Program to manage loss of material in an external environment of plant indoor air. The GALL Report recommends a plant specific AMP for item VII.F2 14. The External Surfaces Monitoring Program description states that visual inspections conducted during system engineer walkdowns are used to identify aging effects. The external surface of heat exchanger tubes would normally be inside the heat exchanger shell and would not be visible during a typical system engineer walkdown. Clarify how a visual inspection during a system walkdown would identify this aging effect. (Please note that LRA Table 3.3.2 5 for the same component and material in a similar external environment, credits the Inspection	<p>The heat exchanger tube side components assigned to the External Surfaces Monitoring Program are not heat exchanger tubes, but the heat exchanger header assembly. This assembly protrudes through the ductwork and connects to the cooling water supply. Drawings M618-0001 and M618-0002 show typical details of the coil and header assembly. Review of the drawings show that the header assembly only protrudes approximately 3" outside of the ducting. This is the location of the flanged header and where it is connected to plant cooling water piping. Thus, the majority of the header assembly is located inside the ducting. LRA Tables 3.3.2-8, 3.3.2-9, 3.3.2-10 and 3.3.2-12 will be amended to place these components in an environment of Ventilation Atmosphere (external) and assign the Inspection of Internal surfaces in Miscellaneous Piping and Ducting Components Program as the aging management program. The following components are affected:</p> <p>Auxiliary Building HVAC System (GL) – LRA Table 3.3.2-8 GALL VII.F2-14 - Heat Exchanger Tube Side (HX# 93,95,97,99,101,103)</p> <table border="1" data-bbox="1043 1158 1915 1504"> <thead> <tr> <th data-bbox="1043 1158 1257 1219">Component No.</th> <th data-bbox="1257 1158 1915 1219">Component Name</th> </tr> </thead> <tbody> <tr> <td data-bbox="1043 1219 1257 1252">SGL09A-02</td> <td data-bbox="1257 1219 1915 1252">SAFETY INJECTION PUMP ROOM COOLER HEAD</td> </tr> <tr> <td data-bbox="1043 1252 1257 1285">SGL09B-02</td> <td data-bbox="1257 1252 1915 1285">SAFETY INJECTION PUMP ROOM COOLER HEAD</td> </tr> <tr> <td data-bbox="1043 1285 1257 1318">SGL10A-02</td> <td data-bbox="1257 1285 1915 1318">RHR PUMP ROOM COOLER HEAD</td> </tr> <tr> <td data-bbox="1043 1318 1257 1351">SGL10B-02</td> <td data-bbox="1257 1318 1915 1351">RHR PUMP ROOM COOLER HEAD</td> </tr> <tr> <td data-bbox="1043 1351 1257 1412">SGL11A-02</td> <td data-bbox="1257 1351 1915 1412">COMPONENT COOL. WATER PUMP ROOM COOLER HEAD</td> </tr> <tr> <td data-bbox="1043 1412 1257 1473">SGL11B-02</td> <td data-bbox="1257 1412 1915 1473">COMPONENT COOL. WATER PUMP ROOM COOLER HEAD</td> </tr> <tr> <td data-bbox="1043 1473 1257 1504">SGL12A-02</td> <td data-bbox="1257 1473 1915 1504">CHARGING PUMP ROOM COOLER HEAD</td> </tr> </tbody> </table>	Component No.	Component Name	SGL09A-02	SAFETY INJECTION PUMP ROOM COOLER HEAD	SGL09B-02	SAFETY INJECTION PUMP ROOM COOLER HEAD	SGL10A-02	RHR PUMP ROOM COOLER HEAD	SGL10B-02	RHR PUMP ROOM COOLER HEAD	SGL11A-02	COMPONENT COOL. WATER PUMP ROOM COOLER HEAD	SGL11B-02	COMPONENT COOL. WATER PUMP ROOM COOLER HEAD	SGL12A-02	CHARGING PUMP ROOM COOLER HEAD
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		of Internal surfaces in Miscellaneous Piping and Ducting Components Program, which includes visual inspection when component is disassembled as part of the surveillance procedure.)	SGL12B-02	CHARGING PUMP ROOM COOLER HEAD
			SGL13A-02	CONTAINMENT SPRAY PUMP ROOM COOLER HEAD
			SGL13B-02	CONTAINMENT SPRAY PUMP ROOM COOLER HEAD
			SGL15A-02	PENETRATION ROOM COOLER HEAD
			SGL15B-02	PENETRATION ROOM COOLER HEAD
			Control Building HVAC System (GK) – LRA Table 3.3.2-9 GALL VII.F1-16 - Heat Exchanger Tube Side (HX# 117,122,123)	
			Component No.	Component Name
			SGK04A-06	CONTROL ROOM A/C UNIT CONDENSER CHANNEL HEAD
			SGK04B-06	CONTROL ROOM A/C UNIT CONDENSER CHANNEL HEAD
			SGK05A-06	CLASS IE ELEC. EQUIP. A/C UNIT CONDENSER CHANNEL HEAD
			SGK05B-06	CLASS IE ELEC. EQUIP. A/C UNIT CONDENSER CHANNEL HEAD
			SGK05A-02	CLASS IE ELEC. EQUIP. A/C UNIT COOLING COIL HEADER
			SGK05B-02	CLASS IE ELEC. EQUIP. A/C UNIT COOLING COIL HEADER
			Fuel Building HVAC System (GG) – LRA Table 3.3.2.10 GALL VII.F2-14 - Heat Exchanger Tube Side (HX# 131)	
			Component No.	Component Name
			SGG04A-02	FUEL POOL COOLING PUMP RM COOLER HEAD
			SGG04B-02	FUEL POOL COOLING PUMP RM COOLER HEAD
			Miscellaneous Buildings HVAC System (GF) – LRA Table 3.3.2-12 GALL VII.F2-14 - Heat Exchanger Tube Side (HX# 137)	
			Component No.	Component Name
			SGF02A-02	AUX FW PUMP ROOM COOLER HEAD
			SGF02B-02	AUX FW PUMP ROOM COOLER HEAD

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AMRA036	3.3	<p>In LRA Table 3.3.2-6, compressed air system, the LRA references Note E and GALL Report item VII.D-2 for carbon steel piping, orifice and valve components. It also credits the Inspection of Internal surfaces in Miscellaneous Piping and Ducting Components Program to manage loss of materials in an internal environment of wetted gas in lieu of the Compressed Air Monitoring Program as recommended by the GALL Report. The AMP recommended by the GALL Report states that checks of air quality is performed as part of preventive actions to ensure that oil, water, rust, dirt, and other contaminants are kept within the specified limits. Since the LRA credits a different AMP, clarify if the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program will perform air quality checks as recommended by the GALL Report.</p>	<p>Air quality checks are not part of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP (XI.M38). The AMP conducts internal visual inspections of compressed air system piping and components to manage cracking, loss of material, and loss of strength. The AMP inspections are not one-time inspections but are periodic inspections.</p> <p>The wetted gas environment listed in LRA Table 3.3.2-6 for the compressed air system applies to two sections of piping and components as discussed below:</p> <p>1.) Dry nitrogen vent piping off the safety-related auxiliary feedwater and main steam atmospheric relief valve accumulators that discharge to atmosphere.</p> <p>See License Renewal Boundary Drawing LR-WCGS-KA-M-12KA05 (B-7, H-7, H-8, D-7, D-8, F-6, F-7, A-4, B-4, and C-4). The internal environment is dry nitrogen that discharges to atmosphere. A wetted gas environment was conservatively chosen since there could be moisture introduced from the outside atmosphere that mixes with the dry nitrogen. Air quality checks based on compressed air from instrument air compressors do not apply. Periodic internal visual inspection of the piping and components provides a positive means for detection of aging effects that could lead to loss of system intended function.</p> <p>2.) Service air containment penetration piping and components on License Renewal Boundary Drawing LR-WCGS-KA-M-12KA02 (D-6).</p> <p>A portion of the piping is safety-related for containment isolation and the attached piping is non-safety related structural integrity attached (SIA). The SIA piping sections are relatively short sections that are easily accessible for periodic internal visual inspection. Periodic internal visual inspection of the piping and components provides a positive means for detection of aging effects that could lead to loss of the SIA intended function.</p> <p>Performance of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP (XI.M38) periodic internal inspections will provide reasonable assurance that compressed air system intended functions are maintained.</p>
AMRA037	3.3	<p>In LRA Table 3.3.1, items 3.3.1-8 and 3.3.1-9, the AMP column did not reflect what is recommended in the GALL Report for the same items. The GALL Report, Volume 1, Table 3, for these lines recommends the</p>	<p>LRA Table 3.3-1, items 3.3.1.08 and 3.3.1.09 AMP columns are incorrect and should reference the Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16) programs. The discussion column of LRA Table 3.3-1, items 3.3.1.08 and 3.3.1.09, specify that the aging management program(s) used to manage aging include the Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.16) programs. These programs are also</p>

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		<p>Water Chemistry Program and a plant specific verification program. LRA Table 3.3.1, only credits a plant specific program. The GALL Report also states that this line item applies to the GALL Report, Volume 2, items VII.E1-5 and VII.E1-7. Clarify this discrepancy and confirm if the information provided in the LRA Table 3.3.1 AMP column is incorrect.</p>	<p>identified for the Chemical and Volume Control System in LRA Section 3.3.2.1.7.</p> <p>Chemical and Volume Control system stainless steel high pressure pumps (meeting the conditions of 3.3.1.09) were assigned GALL line VII.E1-7 and identified both the XI.M2, Water Chemistry and XI.M32, One-Time Inspection aging management programs.</p> <p>Chemical and Volume Control system regenerative heat exchangers (meeting the conditions of 3.3.1.08) were assigned GALL line VII.E1-5 and identified both the XI.M2, Water Chemistry and XI.M32, One-Time Inspection aging management programs.</p> <p>The LRA will be amended as follows:</p> <ul style="list-style-type: none"> - LRA Table 3.3.1, item 3.3.1.08 aging management column to state, "Water Chemistry (B2.1.2) and a plant specific verification program. The AMP is to be augmented by verifying the absence of cracking due to stress corrosion cracking and cyclic loading. A plant specific aging management program is to be evaluated." - LRA Table 3.3.1, item 3.3.1.09 aging management column to state, "Water Chemistry (B2.1.2) and a plant specific verification program. The AMP is to be augmented by verifying the absence of cracking due to stress corrosion cracking and cyclic loading. A plant specific aging management program is to be evaluated."
AMRA038	3.3	<p>In LRA Table 3.3.2-17, floor and equipment drains system, the LRA references Note E and GALL Report, item VII.G-18, for stainless steel tank. The table also credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage loss of materials in an environment of contaminated lubricating oil. The GALL Report item VII.G-18 is for component type piping, piping components, and piping elements. The GALL Report, Chapter IX, Section IX.B, provides definitions of structures and components, the term</p>	<p>The stainless steel reactor coolant pump drain tank receives lubricating oil leakage from the reactor coolant pump motors. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP will manage the loss of material due to pitting and crevice corrosion for stainless steel components in a lubricating oil environment by visual inspections for loss of material. If internal inspections detect loss of material, the aging will be resolved via the WCGS corrective action program.</p> <p>See also AMRA034.</p>

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		<p>pipng, piping components, and piping elements; but it does not include tanks. GALL Report, Section IX.B, defines tanks separately from piping and piping components due to the potential need for a different AMP. The bottom of the stainless steel tank, where contaminated lubricating oil and sediment would collect, is more susceptible to loss of material due to pitting and crevice corrosion than piping components. Confirm if wall thickness of the bottom of the tank is measured as part of the proposed AMP.</p>	
AMRA039	3.3	<p>In LRA Table 3.3.2-14, fire protection system, the LRA references Note J and 1 for elastomer flex hoses in an external environment of plant indoor air. The table also states that there are no aging effects and no AMP required. Note 1 indicates that these components are in an environment of less than 95oF. The normal plant indoor air environment could see high humidity and higher temperatures. In LRA Table 3.3.2 8, for elastomer material in plant indoor air environment, the applicant identified an aging effect of hardening and loss of strength and credited an AMP.</p> <p>Identify where the flex hoses are located in LRA Table 3.3.2 14 and justify why an aging effect is not considered.</p>	<p>The flex hoses are associated with the Halon cylinder banks. Halon cylinder banks are located in the Auxiliary Building, Communications Corridor and Control Building. The general thermal environment in the Control Building is maintained less than 95°F. The general thermal environment in the Auxiliary Building is less than 104°F.</p> <p>Elastomer degradation – hardening and loss of strength. NUREG-1801 Chapter IX.C, defines Elastomers as “materials rubber, EPT, EPDM, PTFE(Teflon), ETFE, viton, vitril, neoprene, and silicone elastomer. Hardening and loss of strength of elastomers can be induced by elevated temperature (over about 95°F (35°C), and additional aging factors such as exposure to ozone, oxidation, and radiation.” NUREG-1801, Chapter IX.D, has a definition for Air-indoor-uncontrolled (>95°F). This definition discusses the temperature threshold for elastomer thermal aging, “If ambient is <95°F, then any resultant thermal aging of organic materials can be considered to be insignificant, over the 60-yr period of interest.” The EPRI guideline, Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Appendix D Section 2.1.8 states in part that, “synthetic rubbers are not affected by ozone and are typically much more resistant to sunlight (or other forms of ultraviolet radiation).”</p> <p>Flexible hoses for Halon storage cylinders in areas other than the Control Building may exceed the temperature threshold for elastomer degradation. Thus, for Halon cylinder flexible hoses in the Auxiliary Building and Communications Corridor, thermal aging must be considered since it cannot be shown that the equipment spaces are below 95°F.</p>

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			<p>Flexible hoses for Halon storage cylinders in the Control Building do not exceed the temperature threshold for elastomer degradation. NUREG-1801 states that if the elastomer temperature threshold is not exceeded, thermal aging is insignificant. The EPRI guide states that synthetic rubbers such as PTFE (Teflon) are not affected by ozone, sunlight or other forms of ultraviolet radiation. Thus, for Halon cylinder flexible hoses in the Control Building, thermal aging need not be considered and hardening - loss of strength is not expected.</p> <p>Changes required:</p> <p>(1) A generic component for flexible hoses will be added for Halon flexible hoses susceptible to thermal aging (Auxiliary Building/Communications Corridor). This generic flexible hose component will be assigned an environment of air-uncontrolled (external) and an aging effect of hardening - loss of strength. The Fire Protection AMP (XI.M26) will be the program used to manage aging. Note "E" will also be used in lieu of Note "J".</p> <p>(2) A generic component for flexible hoses will be added for Halon flexible hoses in the Control Building. This generic flexible hose component will be assigned an environment of air-uncontrolled (external) and the aging effect and aging management programs will be changed to "None". Note "I" will be used in lieu of Note "J".</p> <p>(3) Both new generic components will have an internal environment of dry gas. Note "G" will be assigned since the environment is not in NUREG-1801 for the component and material combination. The aging effect and aging management programs will be changed to "None".</p> <p>The LRA will be amended as follows:</p> <ul style="list-style-type: none"> - LRA Table 3.3.2-14, Fire Protection System, Component Type "Flexible Hoses" (Control Building), environment "dry gas" will be amended to use Note "G,1" in lieu of note "J". Plant specific note #1 will be amended to state, "Ambient temperature in Control Building spaces is expected to be below 95 degrees. Below 95 degrees, thermal aging of elastomers is not considered significant." - LRA Table 3.3.2-14, Fire Protection System, Component Type "Flexible Hoses" (Control Building), environment "plant indoor air" will be amended to use Note "G,1" in lieu of note "J". Plant specific note #1 will be

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			<p>amended to state, "Ambient temperature in Control Building spaces is expected to be below 95°F degrees. Below 95°F degrees, thermal aging of elastomers is not considered significant."</p> <p>- LRA Table 3.3.2-14, Fire Protection System - A new generic component type will be added. Component type: "Flexible Hoses" (Auxiliary Building/Communications Corridor) Material: Elastomer Environment: Plant indoor air (external) Aging Effect: Hardening and loss of strength - elastomer degradation Aging Management Program: XI.M26 - Fire Protection NUREG-1801 Vol. 2 No.: VII.F2-7 Table 1 Item: 3.3.1.11 Note: E,3 Plant Specific Note: #3 - Thermal aging of Halon flexible hoses in the Auxiliary Building and Communication Corridor must be considered because it cannot be shown that these areas are below 95 F.</p> <p>- LRA Table 3.3.2-14, Fire Protection System - A new generic component type will be added. Component type: "Flexible Hoses" (Auxiliary Building/Communications Corridor) Material: Elastomer Environment: Dry gas (internal) Aging Effect: Hardening and loss of strength - elastomer degradation Aging Management Program: XI.M26 - Fire Protection NUREG-1801 Vol. 2 No.: None Table 1 Item: None Note: G,3 Plant Specific Note: #3 - Thermal aging of Halon flexible hoses in the Auxiliary Building and Communication Corridor must be considered because it cannot be shown that these areas are below 95°F.</p> <p>- LRA Section B2.1.12 Fire Protection aging management program will be amended to include discussion of hardening - loss of strength for elastomers.</p>
AMRA040	3.4	The GALL Report includes the extraction steam system as part of the steam and power conversion system. Explain why the extraction steam system is not included within the scope of LRA Section 3.4.	The WCGS system that is equivalent to the NUREG 1801 extraction steam system is the Feedwater Heater Extraction, Drains and Vents (AF) System. The purpose of the WCGS AF System is to provide preheated feedwater to the steam generators to improve cycle efficiency and to minimize thermal stresses on the feedwater piping and steam generator feedwater nozzles. The AF System serves no safety function, has no safety design basis, and does not meet the criteria of 10CFR54.4(a)(1). It

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			<p>is not required to support the requirements of the criteria of 10CFR54.4(a)(3). The components of the AF System are located completely within the turbine building. There are no safety related systems or components located in the turbine building. Any failure of AF System components will not affect any safety related equipment of the plant, thus not meeting the criteria of 10CFR54.4(a)(2). Therefore, the Feedwater Heater Extraction, Drains and Vents System is not included in the scope of license renewal.</p>
AMRA041	3.4	<p>LRA Section 2.1.4.1 states "Thermal insulation was treated as a passive, long-lived component during the scoping and screening process. For systems where it has an intended function, insulation was considered in the scope of license renewal and subject to aging management review..."</p> <p>Explain why there is no aging effect requiring management identified for insulation line items included in LRA Tables 3.4.2-2, 3.4.2-3 and 3.4.2-5.</p>	<p>The piping insulation identified in LRA Tables 3.4.2-2 (main steam system), 3.4.2-3 (feedwater system) and 3.4.2-5 (steam generator blowdown system) is located indoors and is credited for limiting temperatures to containment building system containment penetrations. The insulation also limits steam generator blowdown system piping overpressurization in the containment building during accident conditions. The plant indoor environment is a non-aggressive environment that does not promote aging of the foamglass or calcium silicate insulation materials.</p> <p>There is no industry experience or WCGS operating experience that indicates insulation materials of calcium silicate sheathed in aluminum or foamglass sheathed in stainless steel in non-aggressive environments experience aging effects that require management. The following SERs identified insulation in the scope of license renewal and determined there were no aging effects:</p> <ul style="list-style-type: none"> - NUREG 1785 (H.B. Robinson) - NUREG 1831 (D.C. Cook) - NUREG 1838 (Millstone 2 and 3) - NUREG 1839 (Point Beach 1 and 2) - NUREG 1856 (Brunswick) <p>NUREG 1801 does not evaluate calcium silicate or foamglass insulation materials. NUREG 1801 does conclude there are no aging effects that require management for stainless steel (sheathing) and aluminum (sheathing) in plant indoor air. The calcium silicate and foamglass insulation materials in LRA Tables 3.4.2-2, 3.4.2-3 and 3.4.2-5 are jacketed with stainless steel or aluminum. Therefore, it is concluded that there are no aging effects requiring management for the insulation materials in LRA Tables 3.4.2-2, 3.4.2-3 and 3.4.2-5.</p>
AMRA042	3.4	<p>LRA Section 3.4.2.1.1 describes materials, environment, aging effects requiring management, and AMPs pertaining to the main turbine system. The environments listed in</p>	<p>The purpose of the WCGS main turbine system is to convert steam thermal energy from the main steam system to mechanical energy to drive the main generator. The main turbine system serves no safety function, has no safety design basis, and does not meet the criteria of 10CFR54.4(a)(1). The components of the main turbine system are</p>

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		<p>this section are the plant indoor air and the secondary water. The GALL Report, Section VIII. A, which covers the main turbine system, also includes components exposed to the steam and the lubricating oil environments. Explain why these environments are not addressed in the LRA description and the tables pertinent to the main turbine system.</p>	<p>located completely within the turbine building. Any failure of main turbine system components will not affect any plant safety-related equipment and does not meet the criteria of 10CFR54.4(a)(2). Portions of the main turbine system are in-scope of license renewal to support the requirements of fire protection and ATWS based on the criteria of 10CFR54.4(a)(3). Fire protection requires the turbine to be tripped to support controlled depressurization of the secondary side systems. The fire protection trip function has no in-scope mechanical equipment. ATWS related mechanical equipment is turbine impulse piping and valves with an internal environment of secondary water and external environment of plant indoor air. Secondary water includes steam per LRA Table 3.0-1, Mechanical Environments. Therefore the only environments associated with the main turbine system are secondary water (includes steam) and plant indoor air.</p>
AMRA043	3.4	<p>LRA Table 3.4.2-5, steam generator blowdown system, includes stainless steel pumps exposed to secondary water environment. According to this table, the aging effect requiring management is loss of material. Clarify what is the temperature of the treated water to which these components are exposed to. Justify why cracking is not identified as the aging effect requiring management for these components.</p>	<p>The pumps listed in Table 3.4.4-5 for the steam generator blowdown system are the steam generator drain pumps. The pump bodies are cast austenitic stainless steel (CASS) with an internal environment of secondary water when in use. These pumps are not used during normal plant operation and do not experience elevated temperatures above room ambient temperature during plant operation. The pumps are used for draining the steam generators after the steam generators have been cooled down to near ambient conditions. The pumps are in-scope for spacial interaction since the pumps and piping are not drained after use. The maximum temperature experienced by the pumps is well below the threshold temperature of 482 degrees F for thermal embrittlement of CASS. Cracking is not a consideration for the steam generator drain pumps since they are not normally used to drain the steam generators at fluid temperatures above 140 degrees F. However, WCGS Procedure SYS BM-201, Steam Generator Draining, has a precaution that fluid temperatures could be as high as 150 degrees F. Since steam generator draining is a limited duration evolution not accomplished during normal plant operations, cracking is not a consideration for the steam generator drain pumps.</p>
AMRA044	3.4	<p>LRA Table 3.4.2-6, auxiliary feedwater system, includes several line items pertaining to heat exchangers.</p> <p>a. Clarify what type of heat exchanger is HX # 154. If it is a shell and tube heat exchanger, explain what is flowing through the</p>	<p>The line items in LRA Table 3.4.2-6 all relate to the turbine lube oil cooler which is a shell and tube heat exchanger. Multiple heat exchangers are not being addressed in the table only the turbine lube oil cooler. The heat exchanger (HX) numbers in LRA Table 3.4.2-6 apply to HX subcomponents of the turbine lube oil cooler. The terminology for HX # 154, # 155, # 156, and # 157 is explained in LRA Table 2.3.4-6. The HX shell (#154) is carbon steel, the HX head (#155) is carbon steel, the HX tube sheet (#156) is carbon steel, and the HX tubes (#157) are carbon steel.</p>

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		<p>tubes and which line item addresses the aging management of tubes for this heat exchanger.</p> <p>b. There is one item on tube sides for HX # 155, 156 and 157 exposed to lubricating oil. Reduction of heat transfer or fouling is only addressed for HX # 157. Explain why is the reduction in heat transfer not addressed for HX # 155 and 156. Justify why an aging management is not required for the shell sides of these three heat exchangers.</p> <p>c. There are two line items addressing tube side of heat exchangers (HX # 155, 156, 157) exposed to secondary water (internal) and plant air (external). Clarify what type of heat exchangers are these.</p> <p>d. Provide operating experience (including maintenance) for HX # 154, 155, 156 and 157.</p>	<p>Turbine lube oil flows into the inlet HX head, the turbine lube oil flows through the HX tubes, and out the outlet HX head. Secondary water from downstream of the auxiliary feedwater pump flows into the HX shell and returns to the auxiliary feedwater pump suction. The interior of the HX tubes have an environment of turbine lube oil and an external environment of secondary water. The HX heads have an internal environment of turbine lube oil. The HX shell has an internal environment of secondary water. The HX tube sheets have turbine lube oil on one side and secondary water on the other side. The external environment for both the heads and shell is plant indoor air.</p> <p>Loss of heat transfer applies to the turbine lube oil cooler based on NUREG 1801 line VIII.G-15. Maintenance records and operating experience for the turbine lube oil cooler do not indicate any issues of note. Turbine lube oil sample analyses have been within specifications. Lube oil cooler inspections during turbine overhaul periods have identified no issues.</p>
AMRA045	3.4	LRA Table 3.4.2-6, auxiliary feedwater system, includes a line item for turbine exposed to lubricating oil. Explain which specific components of the turbine are subject to loss of material for exposure to lubricating oil. Confirm that the internal surfaces of these components are within the scope of the One Time Inspection Program.	The auxiliary feedwater steam turbine is included as a component in the main steam system in LRA Table 3.4.2-2. The turbine component type listed in LRA Table 3.4.2-6 for the auxiliary feedwater system is for the auxiliary feedwater turbine lube oil support subcomponents. Included subcomponents are lube oil piping, lube oil sump and lube oil bearing reservoirs. The lube oil pump is a separate item in LRA Table 3.4.2-6. The internal surfaces of the auxiliary feedwater turbine lube oil subcomponents in the auxiliary feedwater system are included in the One Time Inspection Program.
AMRA046	3.4	LRA Table 3.4.2-3, feedwater system, includes several line items pertaining to tube sides of heat exchangers HX # 152 and HX # 153. Describe the type of these heat exchangers and flow conditions in	The line items in LRA Table 3.4.2-3 all relate to the High Pressure (HP) feedwater heaters which are shell and tube heat exchangers. Multiple heat exchangers are not being addressed in the table only the HP feedwater heaters. The heat exchanger (HX) numbers in LRA Table 3.4.2-3 apply to HX subcomponents of the HP feedwater heaters. The terminology for HX # 152 and # 153 is explained in LRA Table 2.3.4-3.

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		tube and shell sides.	HX head (#151) is carbon steel, the HX tube sheet (#152) is carbon steel, the HX tubes (#153) are stainless steel, and the HX shell (#158) is carbon steel. HP secondary water going to the steam generators flows into the inlet HX head, the secondary water flows through the HX tubes, and out the outlet HX head. Secondary water from extraction steam flows into and out of the HX shell. The interior of the HX tubes has an environment of HP secondary water (going to the steam generators) and an external environment of secondary water from extraction steam. The HX heads have an internal environment of secondary water going to the steam generators. The HX shell has an internal environment of secondary water from extraction steam. The HX tube sheets have secondary water on both sides. The external environment for both the heads and shell is plant indoor air.
AMRA047	3.5	LRA Table 3.5.1, item 3.5.1.33, Group 1-5: concrete, states that aging effect is reduction of strength and modulus of concrete due to elevated temperature. Identify which plant specific AMP is being used to manage this aging effect. Explain why Notes E and 3 were used for this item.	<p>As noted in the Discussion column of LRA Table 3.5.1, Item 3.5.1.33, the plant-specific aging management program used to manage this aging effect is the Structures Monitoring Program (B2.1.32).</p> <p>[Note E: Consistent with NUREG-1801 for material, environment, and aging effect, but a different aging management program is credited or NUREG-1801 identifies a plant-specific aging management program.] This note was used because NUREG-1801, item III.A4-1, specifies a plant-specific aging management program.</p> <p>[Note 3: Concrete is monitored for visible signs of aging effects due to increased temperature by Structures Monitoring Program (B2.1.32).] This note was used to clarify the action to be performed by the Structures Monitoring Program as it pertains to this item.</p>
AMRA048	3.5	LRA Table 3.5.2-22, containments, structures, and component supports, lists a component type of "supports ASME 2 and 3" (page 3.5-166). The LRA references Table 1, item 3.5.1.42, and Notes I and 4. However, the table does not provide a definition for Note I. Provide the definition for Note I and explain why this Note was used.	The list of Standard Notes for LRA Table 3.5.2-22 will be amended to add Note I: "Aging effect in NUREG-1801 for this component, material and environment combination is not applicable."
AMRA049	3.5	LRA Table 3.5.1, item 3.5.1.43, corresponds to GALL Report, items III.A3-11 and III.A1-11, which state that masonry block walls are subject to cracking due to restraint	<p>Some Masonry Walls at WCGS are credited as fire barriers, therefore, they must be inspected in accordance with the Fire Protection program (B2.1.12).</p> <p>[Note 1: NUREG-1801 does not provide a line in which concrete masonry</p>

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		<p>shrinkage, creep, and aggressive environment. The GALL Report recommends the Masonry Wall Program to manage this aging effect. The lines referencing item 3.5.1.43 manage this aging effect with the Masonry Wall and the Fire Protection Programs, with no further evaluation recommended. Explain why Notes E and 1 were used for this line item.</p>	<p>is inspected per the Fire Protection program (B2.1.12).] This note was used to explain the addition of the Fire Protection AMP to this line instead of using another line.</p> <p>[Note E: Consistent with NUREG-1801 for material, environment, and aging effect, but a different aging management program is credited or NUREG-1801 identifies a plant-specific aging management program.] This note was used because a different AMP (Fire Protection) is credited.</p>
AMRA050	3.5	<p>In LRA Table 3.5.2-14, a line references to item 3.5.1.45. Explain why Notes E and 3 were used instead of Note A.</p>	<p>LRA Table 3.5.1, Item 3.5.1.45, will be amended to revise the Aging Management Program entry to read: "Inspection of Water-Control Structures (B2.1.33)." This amendment to the LRA will correctly align this item with the SRP.</p> <p>[Note E: Consistent with NUREG-1801 for material, environment, and aging effect, but a different aging management program is credited or NUREG-1801 identifies a plant-specific aging management program.] This note was used because the Structures Monitoring Program is credited instead of Water-Control Structures.</p> <p>[Note 3: WCGS inspects the submerged portions of the Circulating Water Screen House as part of the Structures Monitoring Program (B2.1.32).] This note was used to identify the AMP that is used at WCGS to inspect the CWSH.</p>
AMRA051	3.5	<p>In LRA Section 3.5, Table 2s, there are several lines that reference Note E and GALL Report, item 3.5.1.47, for aging management of loss of material due to general (steel only), pitting and crevice corrosion. For this specific item, the GALL Report recommends the use of the Regulatory Guide 1.127, Inspection of Water Control Structures and a protective coating monitoring and maintenance program. Explain why the Structures Monitoring Program (Note E) was credited instead of the programs recommended by the GALL Report.</p>	<p>NUREG 1801 line III.A6-11 specifies Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.33) as the aging management program for metal components in water-control structures. Regulatory Guide 1.127, does not address metal components, so the Structures Monitoring Program (B2.1.32) is used. WCGS does not rely upon protective coatings to manage the effects of aging.</p>

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AMRA052	3.5	For LRA Table 3.5.1, item 3.5.1.33, provide the maximum temperature that concrete experience in Group 1-5 structures.	<p>USAR Section 3.8.3.4.2 discusses loading on the primary shield wall. During normal plant operation, the primary shield wall concrete temperatures are limited to 150°F except for the area directly below the seal ring support which is limited to 220°F. High energy line containment penetrations have been designed with flued heads to dissipate the heat from these process pipes, and insulation has been installed to further limit the exposure of the concrete. WCGS Technical Specifications require that the containment average air temperature be less than or equal to 120°F.</p> <p>In the auxiliary building, concrete temperatures are limited to 150°F except for local areas, which are limited to 200°F. These limits are maintained by insulation installed on high temperature lines and the plant ventilation system.</p> <p>There are no other in-scope structures that house high temperature lines.</p>
AMRA053	3.5	In LRA Table 3.5.2-16, there is one line that references item 3.5.1.28 and states that crack and distortions will be managed by the Regulatory Guide 1.127, Inspection of Water - Control Structures Associated with Nuclear Power Plants Program. Explain why this AMP is used instead of the Structures Monitoring Program recommended by the GALL Report.	<p>The ESW Discharge Structure is normally submerged and is inspected by divers. It is inspected under WCGS's program that is based on RG 1.127. The Structures Monitoring program credits this program for the ESW Discharge Structure.</p> <p>LRA Table 3.5.2-16 line item that refers to Table 1 line item 3.5.1.28, will be amended to revise the Aging Management Program entry to read: "Structures Monitoring Program (B2.1.32)" and to reference Note A instead of Note E and delete reference to Note 1.</p> <p>The list of Standard Notes for LRA Table 3.5.2-16 will be amended to delete note 1.</p>
AMRA054	3.5	<p>Provide the following information regarding LRA Section 3.5.2.2.2.6:</p> <p>a. Additional information about the bolting material used in structural applications, including group B1.1 application at WCGS:</p> <p>(i) Clarify what is the bolting material.</p> <p>(ii) Clarify what is the normal yield strength and upper-bound as received yield strength.</p> <p>(iii) Describe the WCGS resolution of the bolting integrity generic issue as</p>	<p>a. LRA Table 3.5.2-22 includes a line item for high strength bolting made from high strength, low alloy steel. These bolts are also addressed in LRA Table 3.5.1, Item 3.5.1.51. At WCGS, the maximum ultimate tensile strength for bolts was limited to 170 ksi. Specifications C-134A (Bechtel) and M-730 (Westinghouse), as well as USAR App. 3A, pg 3A-53, limit the bolting materials that can be used at WCGS. Of the bolting materials specified, only SA-540 Grade 21 has a specified minimum yield of equal to or greater than 150 ksi. All other bolting material used at WCGS has a yield strength less than 150 ksi.</p> <p>For high strength bolting to be susceptible to SCC, material with an actual yield strength of greater than 150 ksi must be subjected to excessive bolt preload and contaminants, such as molybdenum sulfide in the thread lubricants. Bolt preload was managed by procedural controls, and lubricants containing detrimental contaminants were not used. Therefore,</p>

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		<p>it relates to structural bolting.</p> <p>(iv) Clarify if any structural bolting has been identified as potentially susceptible to cracking due to SCC. List any structural bolting replaced as part of the resolution.</p> <p>b. Describe the scope and aging management review performed for class MC pressure retaining bolting. Explain how WCGS manages loss of pre-load.</p>	<p>cracking due to SCC is not an aging effect requiring management for high strength bolting at WCGS.</p> <p>A review of plant operating experience has not found any instances of SCC, and no structural bolting has been replaced due to this concern.</p> <p>b. There is no class MC pressure retaining bolting at WCGS. Loss of preload is managed by the Bolting Integrity AMP (LRA Section B2.1.7)</p>
AMRA055	3.5	<p>LRA Table 3.5.2-1, containments, structures, and component supports, lists a component type of penetration which makes reference to Note H. However, the table does not provide a definition for Note H. Provide a definition for this note and justify its use for this specific component.</p>	<p>The list of Standard Notes for LRA Table 3.5.2-1 will be amended to add Note H: "Aging effect not in NUREG-1801 for this component, material and environment combination."</p>
AMRA056	3.5	<p>LRA Table 3.5.2-12, containments, structures, and component supports, lists a component type of liner spent fuel pool which makes reference to Note H. However, the table does not provide a definition for Note H. Provide a definition for this note and justify its use for this specific component.</p>	<p>The list of Standard Notes for LRA Table 3.5.2-12 will be amended to add Note H: "Aging effect not in NUREG-1801 for this component, material and environment combination."</p>
AMRA057	3.6	<p>In LRA Table 3.6.1, item 3.6.1.6, the applicant stated that all fuse holders including the fuses installed for electrical penetration protection are part of larger assemblies, so the applicable GALL Report items were not used. In Interim Staff Guidance (ISG)-5, "Identification and Treatment of Electrical Fuse Holders for License Renewal," the staff provides examples of fuse holders that require an AMR. These are fuses that are installed in fuse holder</p>	<p>a) The electrical containment penetration assemblies at WCGS do not incorporate self-fusing characteristics and must be protected externally. The fuses that are used to protect the electrical containment penetrations are installed in larger assemblies (i.e. motor control center cubicles, main control boards, distribution panels, etc.).</p> <p>b) The WCGS controlled fuse list does not identify which of the over 2500 fuses are used as isolation devices between Class 1E and non-Class 1E electrical circuits. The fuse list does identify the locations for all of the fuses. A review of this list determined that there are no fuses in the scope of license renewal that are not installed as part of a larger assemblies. The aging of the components including the fuse holders within these assemblies is managed as part of the active component. The WCGS</p>

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		<p>panels which are used as protective devices to ensure the integrity of containment electrical penetration or as isolation devices between Class 1E and non-Class 1E electrical circuits.</p> <p>a. List all components in an electrical containment protection assembly and explain why fuse holders installed in this assembly are considered part of a larger active assembly.</p> <p>b. Identify fuse holders installed as isolation devices between Class 1E and non-Class 1E electrical circuits. Explain why these fuse holders do not require an AMR.</p> <p>c. Provide a schematic diagram for electrical containment protection for review during the site visit.</p>	<p>does not install fuse in standalone fuse panels or cabinets.</p> <p>c) Drawings E-13LF08, E-13BB03 and E-13EP02B show typical arrangements of the electrical containment penetration protection circuits.</p>
AMRA058	3.6	<p>In LRA Table 3.6.1, item 3.6.1.12, the applicant takes an exception to the GALL Report for the transmission conductors and connections, and switchyard bus and connections. In addition, the applicant states that the aging effect in the GALL Report for this material and environment combination is not applicable. In LRA Section 3.6.2.2.3, the applicant further states that transmission conductor connections at the time of installation are treated with corrosion inhibitors to avoid connection oxidation and are torqued to avoid loss of pre-load.</p> <p>SRP Section 3.6.2.2.3 states that increased resistance of connections</p>	<p>a) Torque relaxation for bolted connections of switchyard bus and transmission conductors is not a concern at WCGS because stainless steel bolts with stainless steel washers are used to maintain the proper torque and prevent loss of pre-load. The in-scope bolted transmission connections are at the startup transformer XMR01 and disconnect 345-163. These connections are periodically evaluated via thermography as part of the preventive maintenance activities performed on the startup transformer and disconnect. Based on temperature data in the USAR Chapter 2.3, the transmission connections do not experience thermal cycling. The transmission connections are subject to average monthly temperatures ranging from 80 °F in July and August to 29 °F in January with minimal ohmic heating.</p> <p>b) The corrosion inhibitors compound (a grease-type sealant) is a consumable which is used for initial assembly of bolted connections and is replaced as required when connections are taken apart and reassembled (e.g., during routine maintenance). The compound is weather resistant and adheres to the connection to ensure low contact resistance. Based on operating experience, this method of installation has been shown to</p>

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		<p>due to oxidation or loss of pre-load could occurs in transmission conductors and connections, and in switchyard bus and connections. Further, EPRI document TR-104213, "Bolted Joint Maintenance & Application Guide," states that increased temperature difference in electrical bolted joints is due to high circuit rating or increased current duration. The temperature of an electrical bolted joint will rise and stress will increase with increasing current duration. If this temperature increase is not taken into consideration, loose or failure joints will result.</p> <p>a. Explain why torque relaxation for bolted connections of switchyard bus and transmission conductors is not a concern at WCGS.</p> <p>b. Provide a discussion about the qualified life of corrosion inhibitors. Explain why increased resistance of bolted connections due to oxidation is not a concern for switchyard bus and transmission connections.</p> <p>Follow-up: Question 58 - Provide thermographic data for startup XFMR high voltage connections.</p>	<p>provide a corrosion resistant low electrical resistance connection. The WCGS outdoor environment is not subject to industry air pollution or saline environment. The connections do not experience any appreciable aging effects in this environment. Therefore, it is concluded that general corrosion resulting in the oxidation of transmission connection surface metals is not an aging effect requiring management at WCGS. The in-scope bolted connections are at the startup transformer XMR01 and disconnect 345-163. These connections are periodically evaluated via thermography as part of the preventive maintenance activities performed on the startup transformer and disconnect.</p> <p>Periodic thermography will continue into the period of extended operation. A copy of the Infrared Thermography Report dated 10/23/03 for the Startup Transformer was provided along with a copy of the work order history. The thermography results show that based on the transmission line capacity vs the connected load these connections experience minimal to no ohmic heating. These electrical bolted joints do not experience high circuit rating or increased current duration as discussed in EPRI document TR-104213, "Bolted Joint Maintenance & Application Guide."</p> <p>The last paragraph of LRA further evaluation 3.6.2.2.3 will be amended to read the following.</p> <p>The WCGS outdoor environment is not subject to industry air pollution or saline environment. Aluminum bus material, galvanized steel support hardware and stainless steel connection material do not experience any appreciable aging effects in this environment. These connections are periodically evaluated via thermography as part of the preventive maintenance activities performed on the startup transformer and disconnect. The periodic thermography will continue into the period of extended operation.</p>
AMRA059	3.6	<p>GALL Report, Chapter VI, item VI.A-1, cable connections (metallic parts), lists air indoor and air outdoor as the environment. LRA Table 3.6.2-1, lists air indoor; however, it does not include air outdoor environment. Justify why oxidation of cable connections is not an aging effect for</p>	<p>LRA Table 3.6.2-1 will be amended to include electrical cable connections in outdoor air.</p>

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		cable connections in an outdoor environment.	
AMRA060	3.6	GALL Report, Chapter VI, item VI.B-1, identifies adverse localized environment due to heat, radiation, or moisture in the presence of oxygen. LRA Table 3.6.2-1 only lists adverse localized environment (ext). Justify why aging caused by heat, radiation, or moisture is not a concern at WCGS.	LRA Table 3.0-3 defines an Adverse Localized Environment as follows: Adverse localized environments can be due to any of the following: (1) exposure to moisture and voltage (2) heat, radiation, or moisture, in the presence of oxygen (3) heat, radiation, or moisture, in the presence of oxygen or >60-year service limiting temperature, or (4) adverse localized environment caused by heat, radiation, oxygen, moisture, or voltage. The term ">60-year service limiting temperature" refers to that temperature that exceeds the temperature below which the material has a 60-year or greater service lifetime.
AMRA061	3.3	<p>LRA Table 3.3.1, item 3.3.1.69, states that this line is consistent with the GALL Report except that a different AMP is credited for stainless steel piping, piping components, and piping elements exposed to raw water on the internal surfaces. The Fire Water System Program will be credited along with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components to manage the aging effects. This corresponds to several line items in LRA Table 3.3.2-14, fire protection system, where Note E is referenced.</p> <p>Describe how these two programs are used in conjunction to manage these aging effects.</p>	<p>The Fire Water System program manages loss of material for water-based fire protection systems. Periodic hydrant inspections, fire main flushing, sprinkler inspections, and flow tests considering National Fire Protection Association (NFPA) codes and standards ensure that the water-based fire protection systems are capable of performing their intended functions. The Fire Water System program conducts an air or water flow test through each open head spray/sprinkler nozzle to verify that each open head spray/sprinkler nozzle is unobstructed. The Fire Water System program tests a representative sample of fire protection sprinkler heads or replaces those that have been in service for 50 years, using the guidance of NFPA 25 2002 Edition, and tests at 10 year intervals thereafter during the period of extended operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner.</p> <p>Visual inspections evaluating wall thickness to identify evidence of loss of material due to corrosion, ensuring against catastrophic failure, are covered by the aging management program XI.M38 "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components". The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP manages cracking, loss of material and hardening - loss of strength for components whose internal inspections are not covered by other aging management programs. Thus, the Fire Water System program internal visual inspections are covered by the Internal Inspection program. Other inspections such as, fire detection and suppression testing and maintenance, yard fire hydrant inspections and flushing, powerblock fire hose testing, hose station gasket inspections and sprinkler/spray nozzle inspections are covered by the Fire Protection program.</p> <p>Internal visual inspections will be conducted during periodic maintenance, surveillance testing and corrective maintenance to the fire protection</p>

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AMRA062	3.3	<p>LRA Table 3.3.1, item 3.3.1.70, states that this line is consistent with the GALL Report except that a different AMP is credited for copper alloy piping, piping components, and piping elements exposed to raw water on the internal surfaces. The Fire Water System Program will be credited along with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging effects. This corresponds to several line items in LRA Table 3.3.2-14, fire protection system, where Note E is referenced.</p> <p>Describe how these two programs are used in conjunction to manage these aging effects.</p>	<p>system components in the program.</p> <p>The Fire Water System program manages loss of material for water-based fire protection systems. Periodic hydrant inspections, fire main flushing, sprinkler inspections, and flow tests considering National Fire Protection Association (NFPA) codes and standards ensure that the water-based fire protection systems are capable of performing their intended functions. The Fire Water System program conducts an air or water flow test through each open head spray/sprinkler nozzle to verify that each open head spray/sprinkler nozzle is unobstructed. The Fire Water System program tests a representative sample of fire protection sprinkler heads or replaces those that have been in service for 50 years, using the guidance of NFPA 25 2002 Edition, and tests at 10 year intervals thereafter during the period of extended operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner.</p> <p>Visual inspections evaluating wall thickness to identify evidence of loss of material due to corrosion, ensuring against catastrophic failure, are covered by the aging management program XI.M38 "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components". The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP manages cracking, loss of material and hardening - loss of strength for components whose internal inspections are not covered by other aging management programs. Thus, the Fire Water System program internal visual inspections are covered by the Internal Inspection program. Other inspections such as, fire detection and suppression testing and maintenance, yard fire hydrant inspections and flushing, powerblock fire hose testing, hose station gasket inspections and sprinkler/spray nozzle inspections are covered by the Fire Protection program.</p> <p>Internal visual inspections will be conducted during periodic maintenance, surveillance testing and corrective maintenance to the fire protection system components in the program.</p>
AMRA063	3.4	<p>LRA Tables 3.4.2-3 and 3.4.2-6 list several line items related to management of loss of material in steel heat exchanger components exposed to secondary water. These line items refer to LRA Table 3.4-1, item 3.4.1.04, with Note D.</p> <p>LRA Table 3.4-1, item 3.4.1.04,</p>	<p>NUREG 1801 Table VIII.D for PWR Feedwater System has no HX lines, therefore Table line VIII.D1.8 (steel piping in a treated water environment) was used for steel heat exchanger in a treated water environment. NUREG 1801 Table VIII.G for PWR Auxiliary Feedwater System has HX lines but not for steel in treated water, therefore Table line VIII.G-38 was used for steel piping in a treated water environment. Lines VIII.D1.8 and VIII.G-38 provide aging effects/aging mechanism of loss of material/general, pitting, and crevice corrosion and aging management programs of water chemistry and one-time inspection.</p>

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		<p>addresses management of loss of material for steel piping, piping components, and piping elements exposed to treated water. LRA Table 3.4.1, item 3.4.1.03, however; covers loss of material for steel heat exchangers. Even though the line item in LRA Table 3.4-1 is listed for condensate and steam generator blowdown systems, it has the same component, material, environment and aging effect as the line items in Table 3.4.2 3. Explain why LRA Table 3.4.1, item 3.4.1.03, has not been used instead of item 3.4.1.04.</p>	<p>LRA Table 3.4.1, item 3.4.1.03 addresses components in the condensate and blowdown system. NUREG 1801 line VIII.E-37 for the condensate system and NUREG 1801 line VIII.F-28 for the blowdown system evaluate steel HX components in a treated water environment. These lines provide aging effects/aging mechanism of loss of material/general, pitting, and crevice corrosion and aging management programs of water chemistry and one-time inspection.</p> <p>The aging effects, aging mechanism, and aging management programs from NUREG 1801 lines VIII.D1.8 and VIII.G-38 (LRA Table 3.4.1, item 3.4.1.04) are the same as those associated with LRA Table 3.4.1, item 3.4.1.03.</p>
AMRA064	3.4	<p>LRA Tables 3.4.2-2, 3.4.2-3 and 3.4.2-5 include several line items related to insulation materials exposed to the plant indoor air. These items reference Note J and state that there are no aging effects to be managed.</p> <p>Degradation of the thermal insulation on piping and equipment can result in the loss of insulating capability which may cause the area temperature to increase.</p> <p>a. Justify why the degradation of insulating properties is not an issue. b. Provide plant specific and industry operating experience relative to this aspect. c. Clarify if there is environmentally qualified equipment in the vicinity of the insulation and if the temperature rise been evaluated.</p>	<p>The piping insulation identified in LRA Tables 3.4.2-2 (main steam system), 3.4.2-3 (feedwater system) and 3.4.2-5 steam generator blowdown system is located indoors and is credited for limiting temperatures to containment building system containment penetrations. The insulation also limits steam generator blowdown system piping overpressurization in the containment building during accident conditions. The plant indoor environment is a non-aggressive environment that does not promote aging of the foamglass or calcium silicate insulation materials.</p> <p>There is no industry experience or WCGS operating experience that indicates insulation materials of calcium silicate sheathed in aluminum or foamglass sheathed in stainless steel in non-aggressive environments experience aging effects that require management. The following SERs identified insulation in the scope of license renewal and determined there were no aging effects:</p> <ul style="list-style-type: none"> - NUREG 1785 (H.B. Robinson) - NUREG 1831 (D.C. Cook) - NUREG 1838 (Millstone 2 and 3) - NUREG 1839 (Point Beach 1 and 2) - NUREG 1856 (Brunswick) <p>NUREG 1801 does not evaluate calcium silicate or foamglass insulation materials. NUREG 1801 does conclude there are no aging effects that require management for stainless steel (sheathing) and aluminum (sheathing) in plant indoor air. Therefore, it is concluded that there are no aging effects requiring management for the insulation materials in LRA Tables 3.4.2-2, 3.4.2-3 and 3.4.2-5.</p>

Question No	LRA Sec	Audit Question	Final Response
			<p>WCGS calcium silicate and foamglass insulation have no aging effects that require aging management. Therefore, there is no loss of intended function and there are no impacts to room temperatures or nearby equipment or structures due to aging of insulation.</p>
AMRA065	3.4	<p>LRA Table 3.4.2-4 includes a line item pertaining to stainless steel tank exposed to outside atmosphere and weather. The LRA references Note G and states that there are no aging effects requiring management.</p> <p>a. Describe the location of the tank (e.g., above ground, partially buried, bottom touching the soil). b. Justify why no aging effect requiring management is considered for the tank exterior.</p>	<p>a.) The tank in LRA Table 3.4.2-4 is the Condensate Storage Tank (CST). The CST is constructed of stainless steel and is located above ground outside on a concrete foundation. The external environment is atmosphere/weather. Stainless steel exposed to atmosphere/weather has no aging effect or aging mechanism. Note G was selected since the atmosphere/weather environment is not in NUREG 1801 for stainless steel components.</p> <p>b.) NUREG 1801 does not address this environment. The WCGS plant outdoor environment is not subject to industrial air pollution or saline environment. The CST is a Stainless Steel tank located in an outside air environment and are is not exposed to aggressive chemical species. Alternate wetting and drying resulting from rain has shown a tendency to "wash" the exterior surface material rather than concentrate contaminants. This is consistent with NUREG-1843, the Browns Ferry SER, section 3.5.2.3 (pages 3-303 and 3-304) that identifies stainless steel components exposed to an outside air environment are not subject to aging.</p>
AMRA066	3.4	<p>LRA Table 3.4.2-4 includes a line item pertaining to carbon steel closure bolting exposed to atmosphere and weather. The LRA states that loss of preload is an aging effect requiring management and references Notes H and 1.</p> <p>Identify in which equipment these closure bolts are located on. Include a brief discussion as to how the AMP credited for aging management will address this specific aging effect.</p>	<p>Closure bolting is a generic component that is created to cover closure bolting applications under applicable material and environment combinations. In this case closure bolting was created for applications that use carbon steel bolts or studs subject to an atmosphere/weather environment. Examples of plant components include valves and flanges exposed to atmosphere and weather.</p> <p>NUREG 1801 does not have a loss of preload line for closure bolting using carbon steel in an atmosphere/weather environment. This condition resulted in the use of Standard Note H. Plant Specific Note 1 explains that loss of preload applies to this application even though NUREG 1801 does not evaluate steel closure bolting in atmosphere/weather environments. AMP XI.M.18, Bolting Integrity is credited for aging management of this loss of preload application. The requirements of the AMP apply completely for this loss of preload application. The AMP requires that bolting installation plant procedures control joint assembly and control of preload. This includes pre-assembly inspection and cleaning requirements, use of specific bolt torque patterns, use of increased torque application through multiple passes, and verification of uniformity of gasket compression. Post-bolting inspections include</p>

Question No	LRA Sec	Audit Question	Final Response
			verifying contact between the fastener and flange and proper flange alignment.
AMRA067	3.4	<p>LRA Table 3.4.2-3 includes several heat exchanger components which are exposed to plant indoor air and secondary water. The LRA states that loss of material and cracking (in one case) are aging effects requiring management.</p> <p>Justify why heat transfer is not stated as the intended function for these and why loss of heat transfer is not considered as an aging effect requiring management.</p>	The High Pressure (HP) feedwater heaters are in-scope for feedwater system pressure boundary integrity to support post fire safe shutdown requirements per 10CFR54.4(a)(3). Heat transfer is not an intended function for the HP feedwater heaters.
AMRA068	3.2	<p>SRP-LR Section 3.2.2.2.6 states that loss of material due to erosion may occur in the stainless steel high-pressure safety injection (HPSI) pump miniflow recirculation orifice exposed to treated borated water, LRA Section 3.2.2.2.6 addresses loss of material due to erosion. The applicant stated that this aging effect is not applicable because WCGS does not use the safety injection pumps for normal charging; therefore, the applicable GALL Report line item was not used. Provide procedures and/or other documentation that show infrequent use of the HPSI pumps.</p>	<p>The High Pressure Safety Injection pumps are not used for normal charging. The normal and centrifugal charging pumps are part of the Chemical & Volume Control System. USAR Section 9.3.4.2.1.1 discusses the Chemical & Volume Control System Charging, Letdown and Seal Water subsystems. From USAR Section 9.3.4.2.1.1 - Three charging pumps (one "normal" pump and two standby pumps) are provided to take suction from the volume control tank and return the purified reactor coolant to the RCS. Normal charging flow is handled by the normal charging pump.</p> <p>The HPSI mini-flow recirculation lines containing the flow orifices are only used during the Emergency Core Cooling System injection phase when RCS pressure is above pump shutoff head, or during safety injection pump testing. (ref. USAR Section 6.3.2.1)</p>
AMRA069	3.2	<p>SRP-LR Section 3.2.2.2.9 states that loss of material due to general, pitting, crevice, and MIC may occur in steel (with or without coating or wrapping) piping, piping components, and piping elements buried in soil. Buried piping and tanks inspection programs rely on industry practice, frequency of pipe excavation, and operating</p>	<p>Section 3.2.2.2.9 is a roll-up of V.B-9 for Standby Gas Treatment Systems which is a BWR specific system. See NUREG-1800 Table 3.2-1 Item 17; NUREG-1801 Table 2 Item 17; NUREG-1801 line V.B-9. In addition, there is no buried carbon steel piping associated with ESF systems at WCGS.</p>

Question No	LRA Sec	Audit Question	Final Response
		<p>experience to manage the aging effects of loss of material from general, pitting, and crevice corrosion, and MIC. The effectiveness of the buried piping and tanks inspection program should be verified by evaluation of an applicant's inspection frequency and operating experience with buried components to ensure that loss of material does not occur. LRA Section 3.2.2.2.9 addresses loss of material due to general, pitting, crevice, and MIC. The applicant stated that this aging effect is not applicable because WCGS is a PWR. Provide an explanation as to why buried piping is only found at BWRs.</p>	
AMRA070	3.3	<p>Table 3.3.2-16, page 3.3-163, includes a component item "Insulation" of ceramic fiber insulation material. Please explain where this insulation material is used. Also, note 2 at the bottom of Table 3.3.2-16 does not include ceramic fiber insulation materials. Does note 2 apply to this item?</p>	<p>The ceramic fiber insulation is used for diesel generator exhaust line at the penetration of the diesel generation room to prevent overheat of the surrounding concrete. It is made of Kaowool ceramic fiber blanket.</p> <p>The Note 2 of LRA Table 3.3.2-16 will be amended as follows:</p> <p>2 "NUREG-1801 does not consider mechanical insulation. The in-scope thermal insulation is located in areas with non-aggressive environments (meaning the insulation is not exposed to contaminants). Based on the review of the site operating experience, it was determined that for stainless steel insulation, closed cell foam, quilted fiberglass insulation, calcium silicate, ceramic fiber and insulation jacketing in non-aggressive environments, there were no aging effects requiring management."</p>

LICENSE RENEWAL APPLICATION - LIST OF REGULATORY COMMITMENTS

The following table identifies a summary of those actions committed to by Wolf Creek Nuclear Operating Corporation (WCNOC) in the License Renewal Application (LRA) and subsequent LRA correspondence. Any other statements in this submittal are provided for information purposes and are not considered to be commitments. Please direct questions regarding these commitments to Mr. Kevin Moles at (620) 364-4126.

	COMMITMENT SUBJECT	LRA, Appendix A, Section	COMMITMENT DESCRIPTION
1	Boric Acid Corrosion Program (RCMS 2006-198)	A1.4	Prior to the period of extended operation, procedures will be enhanced to state that susceptible components adjacent to potential leakage sources will include electrical components and connectors. Reference: ET 06-0038 Due: March 11, 2025
2	Nickel-Alloy Penetration Nozzles Welded To The Upper Reactor Vessel Closure Heads of Pressurized Water Reactors (RCMS 2006-199)	A1.5	Prior to the period of extended operation, procedures will be enhanced to indicate that detection of leakage or evidence of cracking in the vessel head penetration nozzles or associated welds will cause an immediate reclassification to the "High" susceptibility ranking, commencing from the same outage in which the leakage or cracking is detected. Reference: ET 06-0038 Due: March 11, 2025

	COMMITMENT SUBJECT	LRA, Appendix A, Section	COMMITMENT DESCRIPTION
3	Closed-Cycle Cooling Water System (RCMS 2006-200)	A1.10	<p>Prior to the period of extended operation, a new periodic preventive maintenance activity will be developed to specify performing inspections of the internal surfaces of valve bodies and accessible piping while the valves are disassembled for operational readiness inspections to detect loss of material and fouling. The acceptance criteria will be specified in this Preventive Maintenance activity.</p> <p>Reference: ET 06-0038 Due: March 11, 2025 Revised ET 07-0020</p>
4	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (RCMS 2006-201)	A1.11	<p>Prior to the period of extended operation, procedures will be enhanced to: (1) identify industry standards or Wolf Creek Generating Station (WCGS) specifications that are applicable to the component, and (2) specifically inspect for loss of material due to corrosion or rail wear.</p> <p>Reference: ET 06-0038 Due: March 11, 2025</p>
5	Fire Protection (RCMS 2006-202)	A1.12	<p>Prior to the period of extended operation: (1) fire damper inspection and drop test procedures will be enhanced to inspect damper housing for signs of corrosion, (2) fire barrier and fire door inspection procedures will be enhanced to specify fire barriers and doors described in USAR Appendix 9.5A, "WCGS Fire Protection Comparison to APCSB 9.5-1 Appendix A", and WCGS Fire Hazards Analysis, and (3) training for technicians performing the fire door and fire damper visual inspection will be enhanced to include fire protection inspection requirements and training documentation.</p> <p>Reference: ET 06-0038 Due: March 11, 2025</p>

	COMMITMENT SUBJECT	LRA, Appendix A, Section	COMMITMENT DESCRIPTION
6	Fuel Oil Chemistry (RCMS 2006-203)	A1.14	<p>Prior to the period of extended operation: (1) the emergency fuel oil day tanks will be added to the ten year drain, clean, and internal inspection program, and (2) procedures will be enhanced to provide for supplemental ultrasonic thickness measurements if there are indications of reduced cross sectional thickness found during the visual inspection of the emergency fuel oil storage tanks. A one time ultrasonic (UT) or pulsed eddy current (PEC) thickness examination on the external surface of engine driven fire pump fuel oil tank (1DO002T) will be performed to detect corrosion related wall thinning. If UT is used, the examination will be on a 4 inch grid. The examination will be performed once between 10 and 2 years prior to the period of extended operation.</p> <p>Reference: ET 06-0038 Due: March 11, 2025 Revised ET 07-0020</p>
7	One-Time Inspection (RCMS 2006-204)	A1.16	<p>The One-Time Inspection program conducts one-time inspections of plant system piping and components to verify the effectiveness of the Water Chemistry program (A1.2), Fuel Oil Chemistry program (A1.14), and Lubricating Oil Analysis program (A1.23). This new program will be implemented and completed within the ten-year period prior to the period of extended operation.</p> <p>Reference: ET 06-0038 Due: March 11, 2025</p>
8	Selective Leaching of Materials (RCMS 2006-205)	A1.17	<p>The Selective Leaching of Materials program is a new program that will be implemented prior to the period of extended operation.</p> <p>Reference: ET 06-0038 Due: March 11, 2025</p>

	COMMITMENT SUBJECT	LRA, Appendix A, Section	COMMITMENT DESCRIPTION
9	Buried Piping and Tanks Inspection (RCMS 2006-206)	A1.18	The Buried Piping and Tanks Inspection program is a new program that will be implemented prior to the period of extended operation. Within the ten-year period prior to entering the period of extended operation, an opportunistic or planned inspection will be performed. Upon entering the period of extended operation a planned inspection within ten years will be required unless an opportunistic inspection has occurred within this ten-year period. Reference: ET 06-0038 Due: March 11, 2025
10	One-Time Inspection of ASME Code Class 1 Small-Bore Piping (RCMS 2006-207)	A1.19	The fourth interval of the ISI program at WCGS will provide the results for the one time inspection of ASME Code Class 1 small-bore piping. Reference: ET 06-0038 Due: March 11, 2025
11	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (RCMS 2006-208)	A1.22	The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is a new program that will be implemented prior to the period of extended operation. For those systems or components where inspections of opportunity are insufficient, an inspection will be conducted prior to the period of extended operation to provide reasonable assurance that the intended functions are maintained. Reference: ET 06-0038 Due: March 11, 2025
12	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (RCMS 2006-209)	A1.24	The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is a new program that will be implemented prior to the period of extended operation. Reference: ET 06-0038 Due: March 11, 2025

	COMMITMENT SUBJECT	LRA, Appendix A, Section	COMMITMENT DESCRIPTION
13	Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (RCMS 2006-210)	A1.25	A review of the calibration surveillance test results will be completed before the period of extended operation and every 10 years thereafter. Reference: ET 06-0038 Due: March 11, 2025
14	Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (RCMS 2006-211)	A1.26	The Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is a new program that will be implemented prior to the period of extended operation. Reference: ET 06-0038 Due: March 11, 2025
15	ASME Section XI, Subsection IWL (RCMS 2006-212)	A1.28	Prior to the period of extended operation, procedures will be enhanced to include two new provisions regarding inspection of repair/replacement activities. The 2001 Edition with 2002 and 2003 addenda of ASME Section XI, Subsection IWL, Article IWL-2000, includes two provisions that are not required by the 1998 edition. IWL-2410(d) specifies additional inspections for concrete surface areas affected by a repair/replacement activity, and IWL-2521.2 specifies additional inspections for tendons affected by a repair/replacement activity. In accordance with 10 CFR 50.55a, WCGS will revise their CISI program prior to the next inspection interval to incorporate the ASME Code edition and addenda incorporated into 10 CFR 50.55a at that time. Reference: ET 06-0038 Due: March 11, 2025 Revised ET 07-0020
16	Masonry Wall Program (RCMS 2006-213)	A1.31	Prior to the period of extended operation, procedures will be enhanced to identify unreinforced masonry in the Radwaste Building within the scope of license renewal that requires aging management. Reference: ET 06-0038 Due: March 11, 2025

	COMMITMENT SUBJECT	LRA, Appendix A, Section	COMMITMENT DESCRIPTION
17	Structures Monitoring Program (RCMS 2006-214)	A1.32	<p>Prior to the period of extended operation, procedures will be enhanced to add inspection parameters for treated wood and to monitor groundwater for pH, sulfates, and chlorides. Two samples of groundwater will be tested every five years.</p> <p>Reference: ET 06-0038 Due: March 11, 2025 Revised ET 07-0020</p>
18	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants (RCMS 2006-215)	A1.33	<p>Prior to the period of extended operation, procedures will be enhanced: (1) so that the main dam service spillway and the auxiliary spillway will be inspected in accordance with the same specification, (2) to clarify the scope of inspections for the spillways, (3) to add the 5 year inspection frequency for the main dam service spillway, and (4) to add cavitation to the list of concrete aging effects for surfaces other than spillways.</p> <p>Reference: ET 06-0038 Due: March 11, 2025</p>
19	Reactor Coolant System Supplement (RCMS 2006-216)	A1.35	<p>WCNOC will:</p> <p>A. Reactor Coolant System Nickel Alloy Pressure Boundary Components Implement applicable (1) NRC Orders, Bulletins and Generic Letters associated with nickel alloys and (2) staff-accepted industry guidelines, and</p> <p>B. Reactor Vessel Internals (1) Participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, WCNOC will submit an inspection plan for reactor internals to the NRC for review and approval.</p> <p>Reference: ET 06-0038 A, B(1), B(2) Due: March 11, 2025 B(3) Due: March 11, 2023</p>

	COMMITMENT SUBJECT	LRA, Appendix A, Section	COMMITMENT DESCRIPTION
20	Electrical Cable Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements (RCMS 2006-217)	A1.36	<p>Prior to the period of extended operation, the infrared thermography testing procedure will be enhanced to require an engineering evaluation when test acceptance criteria are not met. This engineering evaluation will include identifying the extent of condition, the potential root cause for not meeting the test acceptance, and the likelihood of recurrence.</p> <p>Reference: ET 06-0038 Due: March 11, 2025</p>

	COMMITMENT SUBJECT	LRA, Appendix A, Section	COMMITMENT DESCRIPTION
21	Metal Fatigue of Reactor Coolant Pressure Boundary (RCMS 2006-218)	A2.1	<p>Prior to the period of extended operation, the Metal Fatigue of Reactor Coolant Pressure Boundary program will be enhanced to include: (1) Action levels to ensure that if the fatigue usage factor calculated by the code analysis is reached at any monitored location, appropriate evaluations and actions will be invoked to maintain the analytical basis of the leak-before-break (LBB) analysis and of the high-energy line break (HELB) locations, or to revise them as required, (2) Action levels to ensure that appropriate evaluations and actions will be invoked to maintain the bases of safety determinations that depend upon fatigue analyses, if the fatigue usage factor at any monitored location approaches 1.0, or if the fatigue usage factor at any monitored NUREG/CR6260 location approaches 1.0 when multiplied by the environmental effect factor F_{EN}, (3) Corrective actions, on approach to these action levels, that will determine whether the scope of the monitoring program must be enlarged to include additional affected reactor coolant pressure boundary locations in order to ensure that additional locations do not approach the code limit without an appropriate action, and to ensure that the bases of the LBB and HELB analyses are maintained, (4) 10 CFR 50 Appendix B procedural and record requirements.</p> <p>Prior to the period of extended operation, changes in available monitoring technology or in the analyses themselves may permit different action limits and action statements, or may re-define the program features and actions required to address the fatigue time-limited aging analyses (TLAAs).</p> <p>Reference: ET 06-0038 Due: March 11, 2025</p>
22			Deleted

	COMMITMENT SUBJECT	LRA, Appendix A, Section	COMMITMENT DESCRIPTION
23	Concrete Containment Tendon Prestress (RCMS 2006-220)	A2.3	<p>Prior to the period of extended operation, procedures will be revised to: (1) extend the list of surveillance tendons to include random samples for the year 40, 45, 50, and 55 year surveillances, (2) explicitly require a regression analysis for each tendon group after every surveillance, (3) invoke and describe regression analysis methods used to construct the lift-off trend lines, (4) extend surveillance program predicted force lines for the vertical and hoop tendon groups to 60 years, and (5) conform procedure descriptions of acceptance criteria action levels to the ASME Code, Subsection IWL 3221 descriptions.</p> <p>Reference: ET 06-0038 Due: March 11, 2025</p>
24	ASME III Subsection NG Fatigue Analysis of Reactor Pressure Vessel Internals (RCMS 2006-221)	A3.2.2	<p>WCNOC will obtain a design report amendment to either quantify the increase in high-cycle fatigue effects, or to confirm that the increase will be negligible. WCNOC will complete this action before the end of the current licensed operating period.</p> <p>Reference: ET 06-0038 Due: March 11, 2025</p>
25	Assumed Thermal Cycle Count for Allowable Secondary Stress Range Reduction Factor in B31.1 and ASME III Class 2 and 3 Piping (RCMS 2006-222)	A3.2.4	<p>WCNOC will complete the reanalysis of the reactor coolant sample lines and any additional corrective actions or modifications indicated by them, before the end of the current licensed operating period.</p> <p>Reference: ET 06-0038 Due: March 11, 2025</p>

	COMMITMENT SUBJECT	LRA, Appendix A, Section	COMMITMENT DESCRIPTION
26	USAR Supplement (RCMS 2006-223)	A0	Following issuance of the renewed operating license in accordance with 10 CFR 50.71(e), WCNOG will incorporate the USAR supplement into the WCGS USAR as required by 54.21(d). Reference: ET 06-0038 Due: USAR update following issuance of the renewed operating license in accordance with 10CFR 50.71(e). Revised ET 07-0020
27	Pressure-Temperature (P-T) Limits (RCMS 2006-224)	A3.1.3	WCNOG will revise the Pressure and Temperature Limits Report for a 60-year licensed operating life. Reference: ET 06-0038 Due: March 11, 2025
28	Implementation of New Programs (RCMS 2006-225)	N/A	Implementation of new programs may require additional action items not included in this list. WCGS is committed to including new program elements in the corrective action program. Reference: ET 06-0038 Due: March 11, 2025
29	LRA Amendment (RCMS 2007-250)	N/A	License Renewal Application changes discussed in ET 07-0011 will be submitted in an amendment to the Application. Reference: ET 07-0011 Due: July 20, 2007
30	Nickel Alloy Aging Management Program (RCMS 2007-251)	A1.34	The WCGS Nickel Alloy Aging Management inspection plan will be submitted for NRC review and approval at least 24 months prior to entering the period of extended operation Reference: ET 07-0016 Due: March 11, 2023
31	LRA Amendment (RCMS 2007-252)	N/A	License Renewal Application changes discussed in ET 07-0020 will be submitted in an amendment to the Application. Reference: ET 07-0020 Due: August 31, 2007

	COMMITMENT SUBJECT	LRA, Appendix A, Section	COMMITMENT DESCRIPTION
32	Closed-Cycle Cooling Water System (RCMS 2007-253)	N/A	WCNOC Procedure QCP-20-518, "Visual Examination of Heat Exchangers and Piping Components", will be revised to define cracking, provide additional guidance for detection of cracking and specific acceptance criteria relating to "as found" cracking. Reference: ET 07-0020 Due: March 11, 2025