DiabloCanyonNPEm Resource

From:	Rigel.Davis@aps.com
Sent:	Tuesday, July 13, 2010 12:40 PM
To:	Pick, Greg
Cc:	TLG1@pge.com
Subject:	Diablo Canyon LR Procedures (1 of 2)
Attachments:	ER Work Guideline Rev 4.pdf; PI-1 Scoping & Screening Rev 4 Oct-12-07.pdf; TR-8DC Aging Effects TR Rev2 05-25-10.pdf; DG-6 Boundary Drawings Rev 0 Aug 01-2008.pdf; TR-3-DC Fire Protection Rev 1 February 24, 2010.doc; TR-6DC Criterion a(2) Rev 1, Jan 28, 2010.doc; PI-3 TLAA Rev 1 Feb-14-07-pdf.pdf; TR-10DC Insulation Rev 1 - January 28-2010.doc; IPA Work Guideline Rev 7.pdf; TR-13DC Specs-Stds Rev 1 January 29, 2010.doc; TR-12DC Revision 1 January 29 2010.doc; TR-9DC Systems and AMPs Rev 3 May 27-2010.pdf; TR-7DC Elec Pos Paper Rev 1, Jan 21, 2010.doc; TR-2DC SBO Pos Paper Rev 2 January 29 2010.doc; TR-1DC ATWS Pos Paper Rev 2 January 21 2010.doc; DG-4 Heat Exchangers Rev2 020807-pdf.pdf; TR-4DC EQ Pos Paper Rev1 April 3,2009.doc; TR-5DC PTS Pos Paper Rev 1 June 13 2009.doc; TR-11DC Electrical Component Rev 0 Janaury 26 2010.doc

Hi Greg,

This is the first of two emails transmitting the License Renewal administrative procedures used for the development of the application.

Thank you,

Rye Davis
STARS License Renewal - Diablo Canyon
rigel.davis@aps.com
623-393-5225

Hearing Identifier: DiabloCanyon_LicenseRenewal_NonPublic
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Mail Envelope Properties (EDA19031256D904E94EB13FFC07A787607B75C71A4)

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Sent Date: 7/13/2010 12:40:14 PM
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From: Rigel.Davis@aps.com

Created By: Rigel.Davis@aps.com

Recipients:
"TLG1@pge.com" <TLG1@pge.com>
Tracking Status: None
"Pick, Greg" <Greg.Pick@nrc.gov>
Tracking Status: None

Post Office: VM252.apsc.com

Files	Size	Date & Time
MESSAGE	260	7/13/2010 12:41:58 PM
ER Work Guideline Rev 4.pdf	613848	
PI-1 Scoping & Screening Rev 4 Oct-12-07.pdf	527215	
TR-8DC Aging Effects TR Rev2 05-25-10.pdf	445874	
DG-6 Boundary Drawings Rev 0 Aug 01-2008.pdf	333184	
TR-3-DC Fire Protection Rev 1 February 24, 2010.doc	304192	
TR-6DC Criterion a(2) Rev 1, Jan 28, 2010.doc	298048	
PI-3 TLAA Rev 1 Feb-14-07-pdf.pdf	280778	
TR-10DC Insulation Rev 1 - January 28-2010.doc	280128	
IPA Work Guideline Rev 7.pdf	279455	
TR-13DC Specs-Stds Rev 1 January 29, 2010.doc	217664	
TR-12DC Revision 1 January 29 2010.doc	213056	
TR-9DC Systems and AMPs Rev 3 May 27-2010.pdf	209919	
TR-7DC Elec Pos Paper Rev 1, Jan 21, 2010.doc	197184	
TR-2DC SBO Pos Paper Rev 2 January 29 2010.doc	193600	
TR-1DC ATWS Pos Paper Rev 2 January 21 2010.doc	159808	
DG-4 Heat Exchangers Rev2 020807-pdf.pdf	145169	
TR-4DC EQ Pos Paper Rev1 April 3,2009.doc	128064	
TR-5DC PTS Pos Paper Rev 1 June 13 2009.doc	107072	
TR-11DC Electrical Component Rev 0 Janaury 26 2010.doc	1023040	

Options
Priority: Standard
Return Notification: No
Reply Requested: No
Sensitivity: Normal
Expiration Date:
Recipients Received:

LICENSE RENEWAL FEASIBILITY STUDY

WORK GUIDELINE 2

ENVIRONMENTAL REPORT

Manager Approval/ Terence L Grebel Date/ 10/20/09

Revision 4
October 2009

FOREWORD

This work guideline describes the process developed by the License Renewal Feasibility Study (LRFS) to prepare and submit an Environmental Report for the License Renewal Feasibility Study at Diablo Canyon Power Plant (DCPP). This work guideline is in accordance with the LRFS Project Plan and is intended to provide specific details and working-level guidance for draft License Renewal Applications or, more specifically, the draft Environmental Report. As appropriate, guidelines for interfacing with contractors related to preparation of the Environmental Report are addressed.

The work guidelines are designated to ensure the following:

- Documents prepared to support the environmental portion of license renewal are accurate, complete, consistent, and address all pertinent regulatory requirements.

- The Environmental Report receives thorough technical, management, and peer reviews.

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1. APPLICABLE REGULATIONS AND GUIDANCE

The primary regulation applicable to License Renewal Environmental Reports is 10 CFR 51, "Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions." Compliance with this regulation is mandatory; exemptions require formal approval by the NRC. Generally, a formal request for exemption must be submitted by the licensee for NRC review before such as exemption can be granted. The request must cite compelling reasons why an exemption would be in the best interest of the parties involved with the exemption request. Even then, the Commission may reject the request unless compliance would result in undue hardship or costs, or the proposed exemption would result in a clear benefit to the public's health and safety. Therefore, every effort should be made by PG&E to ensure not only that compliance with regulations is achieved, but also that such compliance is clearly and completely documented.

NRC guidance documents, such as Regulatory Guides (RGs) and Standard Review Plans (SRPs), provide specific guidance on acceptable methods to implement and demonstrate compliance with regulations. While RGs are not regulatory requirements, the guidance details provided in a RG effectively become regulatory requirements once a licensee commits to conformance with the RG. Further, much of the information contained in the SRPs should be viewed as equivalent to requirements as the NRC staff uses such information in identifying compliance with or deviation from regulations.

The Environmental Report will be prepared in accordance with Supplement 1 to RG 4.2, "Preparation of Supplemental Environmental Reports for Applications to Renew Nuclear Power Plant Operating Licenses." As the title implies, this RG supplies guidance for preparing the ER. Much of the information specified in the RG as necessary in an ER may already be contained in docketed material previously submitted to the NRC by PG&E. Thus, inclusion on the ER of the information requested by Supplement 1 to RG 4.2 may be simplified or shortened by reference to previously docketed material, such as the Independent Spent Fuel Storage Installation (ISFSI) or Steam Generator Replacement Project (SGRP) ERs.

The SRP (NUREG-1555) for license renewal provides additional guidance applicable to preparation of the ER. The guidance is particularly important because it describes the process used by the NRC staff to review and assess an applicant's compliance with regulations.

The Generic Environmental Impact Statement (GEIS), NUREG-1437, assesses the scope and impact of environmental effects at all of the currently existing U.S. nuclear power plant sites. The conclusions of the GEIS provide a list of issues that were analyzed and resolved in a generic fashion and a list of issues that require a site-specific analysis. For issues which were resolved in a generic fashion, plants perform a review to determine if there is any new or significant information that would cause a need for a site-specific analysis of the issue.

A supplemental EIS (SEIS) updates or supplements the existing GEIS. For license renewal, the Commission directed the staff to issue site-specific supplements to NUREG-1437 for each application.

In addition to NRC guidance, previous License Renewal applicants' documents and previous DCPP environmental documents will be used for preparation guidance. These documents include docketed License Renewal Applications and docketed DCPP environmental reports for the Independent Spent Fuel Storage Installation and Steam Generator Replacement Project.

2. RESPONSIBILITIES

Responsibilities for various PG&E personnel and industry reviewers with regard to preparation of the License Renewal Feasibility Study Environmental Report for Diablo Canyon are as follows:

- Vice President, Nuclear Technical Services, Vice President and Plant Manager, DCPP:
  - Provide resources to prepare and review sections of the Environmental Report.
- Manager, Regulatory Projects:
  - Ensure the draft LRA complies with regulatory requirements.
- Managers, Directors, or Department Heads:
  - Designate, as appropriate, the lead personnel for each Environmental Report section data package, as agreed upon in the Service Level Agreement.
  - Designate, as appropriate, authors and reviewers for each section of the report, as agreed upon in the Service Level Agreement.
- LRFS and ER Project Managers:
  - Maintain the schedule and budget as agreed upon in the Service level Agreement.
- Lead Project Engineer:
  - Interface with lead authors to ensure conformance with license renewal processes.
  - Ensure compliance with applicable regulatory requirements or provide adequate justification for noncompliance.
  - Coordinate resolution of comments.
- Lead Authors:
  - Develop drafts of assigned data packages.
  - Use appropriate codes and standards, existing docketed materials, and other resources as needed to prepare assigned sections.
  - Identify and include copies in the data packages of all reference materials used to develop draft write-ups for each section.
- Independent Technical Reviewer:
  - Independently verifies that the technical information is complete and accurate and meets the applicable regulatory requirements in assigned sections.

- Subject Matter Expert:

  - Reviews assigned sections for technical accuracy in the reviewer's discipline.
  - Imparts the PG&E Corporate point-of –view regarding ER commitments.

- Plant Staff Review Committee (PSRC) and Sub-Committee:

  - Reviews the draft LRA.

- Legal:

  - Reviews assigned sections for legal adequacy and alignment with corporate law views.

- Industry Peer Reviewers:

  - Performs a preliminary review on all individual sections for consistency and appropriate level-of-detail as compared to previous License Renewal applicants. For DCPP, section industry peer reviewers are limited to San Onofre Nuclear Generating Station (SONGS), Palo Verde Nuclear Generating Station (PVNGS), Beaver Valley Power Station (BVPS), and one outside lawyer consulting firm.
  - Performs a final review of the integrated Environmental Report for consistency and appropriate level-of-detail as compared to previous License Renewal applicants. If applicable, the reviewers also verify that previous individual section comments were addressed appropriately. For DCPP, integrated industry peer reviewers include SONGS, PVNGS, Callaway, and Enercon Services.

3. DATA PACKAGES

Data packages are developed for each section of the ER. Individual packages for subsections within the report are developed by designating one package for each second or third-level section of the report. (For instance, a data package consists of Section 4.19 in the ER, a separate package exists for 4.20, etc.)

3.1 Development of the document

The basis of developing a quality Environmental Report section is using successful NRC-accepted approaches, documents, and up-to-date references. In order to ensure that these are included in the development of all ER sections, the following methodology should be used:

1. Obtain and review at least three previously submitted License Renewal Applications. Note the level of detail and subject matter.
2. Compare the previously submitted LRA's to RG 4.2 Supplement 1 recommendations.
3. Choose previous applicant(s) ER section(s) by which to model DCPP's ER section.
4. Obtain and review previous DCPP environmental documents, such as the ISFSI ER and the SGRP ER and EIS.
5. Mold the recent DCPP environmental documents to the format and level-of-detail required for the LRFS ER.
6. Verify references are up-to-date and still applicable to the subject.
7. Verify the level-of-detail is in line with NUREG-1555, the NRC's Standard Review Plan.

3.1 Contents

The specific data packages, assigned individuals, and first and final draft target dates are provided in a list that is periodically updated and distributed to all involved project personnel.

A hard copy of each data package is maintained in a binder that contains several divisions addressing similar items: an open items list; applicable regulations, RGs, and SRPs to identify the section's regulatory requirements; current draft of the section addressed by the package; industry examples of previous applicable ER and SEIS sections (including applicable RAIs); applicable sections from recent DCPP environmental reviews (e.g., ISFSI EIR, ISFSI ER, FES, and SGRP EIR); a completed New and Significant Information Form; and source and reference material that support preparation of the draft.

3.3 Hard Copy – Binders

Hard-copy information pertinent to each data package is contained in the individual binders for the particular package. The lead engineer and author are responsible for maintaining each data package up-to-date. The hard-copies are for informational use and are not considered the master copy of record. As updated information is entered into the package, the earlier material may be discarded, except for earlier drafts and comments for each section, which are maintained for historical reference and traceability.

3.4 Electronic Copies – SharePoint

Sections from the data package are electronically stored on the project SharePoint to facilitate document accessibility and ease of revision by personnel at different locations. Some reference material may need to be scanned onto the SharePoint.

The lead section engineer and author will electronically store their ER section on the SharePoint. The SharePoint files are maintained up-to-date, just like the hard-copy binders. The ability to make changes or updates to files is limited to designated LRFS team members, the lead engineer, and lead author who have been granted such authorization.

3.5 Word Processing

The License Renewal Environmental Report must be prepared in a readily retrievable fashion that allows continuous revisions through the development effort. Therefore, the section drafts are electronically processed using Word for Windows and stored on the SharePoint to facilitate their documentation and retrieval in a controlled process. Further, it is important to specify and maintain the format and style of these documents so that any revisions thereto can be verified. It is also important to maintain the correct text styles, particularly for the final copy of the report to be submitted to the NRC and for subsequent revisions thereto.

In particular, the documents are processed with Word using Arial for font style. Margins for text are one inch on each side of the page, with headers having one line space from the main text. The font size for text is generally 12, but page numbers are in size 11. The font size for tables can vary from 11, depending on table size and page limitations. The font size for titles to chapters is 14. Line spacing is single space within paragraphs of text and double space between paragraphs and section headings. Figures are either scanned onto the SharePoint, or prepared and stored electronically on the SharePoint, as appropriate.

Chapter titles are all upper case letters in bold text. All section headings are itemized in sequential numeric order in bold text, with subdivisions separated by periods. The first level section headings (e.g., 8.1) are all upper case with underlines. The second level headings (8.1.1) are all upper case with no underlines. The third and higher levels (8.1.1.1, etc.) are regular title text where only the first character in each word is upper case. If the title heading wraps around, the second line of the heading is flush with the beginning of the first line of the heading. Should there be subsections within the text that have no corresponding subsection numbers, the subsection headings are italicized for highlighting but not in bold.

Table and figure numbering shall be formatted with the section number then with the next sequential table of figure number (e.g., 2.1-1, 2.1-2, etc.).

Numerals are used for denoting references (e.g., (Reference 1)). The list of references is provided at the end of each chapter as an added section. References used for the internal PG&E review process shall be bolded. The bolded references shall be removed prior to Owner's Acceptance of Revision 0.

Alphabetical notations for footnotes are included in the text as superscripts. The footnotes are located automatically at the bottom of the noted page if the text notation is inserted using the Word command. Footnotes start with the letter “a” on each page and are alphabetically sequenced if multiple footnotes appear on the same page, independent of any other footnote in the document. The footnote itself needs to be reset to Arial, font size 11. A footnote paragraph needs to be reset to full indent. While a footnote paragraph is single spaced, multiple paragraphs of the footnote or another footnote would be separated by a double space.

The titles of the facility and the document appear left-justified in the footer, in font size 12. The section of the LRA and the title of the document appear bolded, right-justified in the header. Page numbers are not included on pages designated for figures and tables. Page numbers and section headings within the individual sections of each chapter are linked via the Word command to facilitate automatic corrections to the Table of Contents for the chapter so that there is no need to manually adjust tables of contents during the revision process. Finally, the use of automatic bullets and numbering in the Word command is minimized to facilitate the ease of changes to itemized lists during the revision process.

An example page from a draft section of the ER is provided in Attachment B to illustrate the desired format.

3.6 Document Preparation for Submittal to NRC

The License Renewal Environmental Report must be prepared in such a fashion that is acceptable to the NRC. The lead project engineer will be responsible for ensuring that the Environmental Report is converted to PDF format using the guidelines in the NRC Desk Reference Guide for PDF Generation (NRC 2007). Further, the Environmental Report will be hyperlinked consistent with previous License Renewal applicants’ documents. Typically, hyperlinks are provides for all sections, references, tables, and figures.

4. CORRESPONDENCE PROTOCOL

Although not required by federal law or NRC regulation, PG&E has chosen to invite comment from federal and state agencies regarding potential effects that DCPP license renewal might have.

Using previous License Renewal applicants' agency consultations as examples, the PG&E subject matter experts will draft the PG&E consultation letters. Agency contact information is to be obtained from agency websites or through PG&E Corporate offices. PG&E signees will be designated by the project manager and lead project engineer for each agency that is consulted. The reviewers should include, at a minimum, the following individuals:

- One or more subject matter experts to review for technical accuracy in their discipline areas
- Legal
- Project Manager
- Project Technical Reviewer

Once a final draft of the consultation letter is complete, the letter may be sent to the agreed upon agencies. A PDF copy of the letter will be maintained on the SharePoint in the references section for Attachment C of the Environmental Report.

Additionally, the lead project engineer will maintain an agency correspondence log. This log will be used to track the responses of each agency and the actions that will be required to comply with the agency's requests.

If an agency response is received, the PG&E signee shall scan the response letter and post it on the SharePoint. The original letter shall be provided to the lead project engineer for inclusion in Attachment C of the Environmental Report.

5. REVIEWS

5.1 First Draft Reviews

Once a first draft has been completed by the section author, a limited number of working level and supervisory personnel perform a project review using XI1.ID1 as guidance. All applicable guidance documents outlined in Section 1 of this guideline, in addition to generic data package items (e.g., RAIs, New and Significant Information Forms, recent DCPP ERs), are used in this review. The reviewers should include, at a minimum, the following individuals:

Primary Reviewers:

- One or more subject matter experts to review for technical accuracy in their discipline areas
- An ITR to review for technical accuracy, completeness, and compliance with checklist requirement
- Project Manager

Secondary Reviewers:

- Legal
- Project Engineer Reviewer
- Industry Peers

The reviewers can access the drafts from the SharePoint for viewing. Figures or other material that cannot be forwarded electronically or not otherwise available on the SharePoint are forwarded by hard copy as necessary.

The lead project engineer coordinates the review activities to ensure that timely reviews and responses are received. The lead project engineer and the lead author then work together to resolve comments for incorporation into the first drafts. Comments from the initial draft review must be addressed before additional drafts can be issued. Comments and dispositions are documented for each section and are stored on the SharePoint. XI1.ID1 Record of Review Checklists are completed for each section and are also stored on the SharePoint. A current version of the XI1.ID1, Record of Review Checklist, should be obtained after each section review is completed (FileNET location: NPG Library:/NPG Manual/00, Forms). The Record of Review Checklists should be maintained for informational purposes only and should not be considered the final Record of Review for the Environmental Report.

5.2 Management Phase Reviews

Management phase reviews are to be performed once earlier comments have been resolved and incorporated and editorial improvements and format adjustments have been made.

A phase review package may contain sections from several work packages that relate to a similar subject matter. Each section should include the current ER section revision, applicable New and Significant Information Forms, section comments and dispositions, and a Record of Review Checklist. Reviewers should include, at a minimum, the following individuals:

- Legal
- PSRC Sub-Committee

The lead author and lead project engineer work together to resolve and incorporate technical comments.

5.3 Integration Review (XI1.ID1 Phase 2 Review)

Once all individual sections have been reviewed by management, and assembled as a complete Environmental Report, an integration review will be performed. Reviewers will perform a final review for consistency and appropriate level-of-detail as compared to previous License Renewal applicants. If applicable, the reviewers also verify that previous individual section comments were addressed appropriately. Reviewers should include, at a minimum, the following individuals:

Primary Reviewers:

- One or more subject matter experts to review for technical accuracy in their discipline areas
- An ITR to review for technical accuracy, completeness, and compliance with checklist requirement
- Project Manager

Secondary Reviewers:

- Legal
- Industry Peers

The lead author and lead project engineer work together to resolve and incorporate technical comments. Prior to the complete Draft Application review, the lead project engineer will update and/or verify the references used in the Environmental Report.

In accordance with XI1.ID1, this integration review will be considered the final review-of-record (XI1.ID1 Phase 2 Review). A current version of the XI1.ID1, Record of Review Checklist, should be obtained and completed (FileNET location: NPG Library:/NPG Manual/00, Forms). The Record of Review Checklist should be signed after PSRC review of the final Environmental Report.

5.4 Complete Draft Application Review

PSRC will review and approve the draft License Renewal Application, which includes the Environmental Report. To facilitate the process, the PSRC may review the application in parts. An Environmental Report review flow chart is displayed in Attachment D.

5.5 Other Reviews

This draft Application is not intended to be submitted to the NRC prior to PG&E Corporate review.

6. STATUS REPORTS AND PRESENTING INFORMATION TO MANAGEMENT

The License Renewal Feasibility Study is managed according to DCPP Project Management procedure AD7.ID8. The LRFS Project Manager or designee will update the DCPP Project Management Database Project Status Report on a monthly basis. Secondly, an LRFS Monthly Status Report will be distributed to appropriate PG&E and industry personnel. The LRFS Monthly Status Report includes sections addressing the Environmental Report. In addition to these monthly updates, throughout the Environmental Report development phase, there are numerous opportunities to present status reports directly to management. The following format shall be used when presenting a status update to management:

- Project Summary
  - Safety
  - Quality
  - Risks
  - Mitigation
  - Contingency
  - Leadership Decisions/Support or Actions

- Project Scope
  - Scope Analysis
  - Cost Analysis

- Project Schedule
  - Schedule Analysis

7. NRC REQUESTS FOR ADDITIONAL INFORMATION

After submittal of the Environmental Report, the NRC may require additional information to complete their review. If a Request for Additional Information (RAI) is received, the response should be tracked to completion in accordance with XI1.ID1, Section 5.3 and XI4.ID1, Section 5.4. A Notification should be initiated and assigned to the appropriate subject matter expert or License Renewal team member.

ATTACHMENT A

ENVIRONMENTAL REPORT CONTENTS

ATTACHMENT B

EXAMPLE ER SECTION

4.19 HISTORIC AND ARCHAEOLOGICAL RESOURCES

NRC

The environmental report must contain as assessment of "…whether any historic or archaeological properties will be affected by the proposed project." 10 CFR 51.53(1)(3)(ii)(K)

"Generally, plant refurbishment and continued operation are expected to have no more than small adverse impacts on historic and archaeological resources. However, the National Historic Preservation Act requires the Federal agency to consult with the State Historic Preservation Officer to determine whether there are properties present that require protection." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 71

"Sites are considered to have small impacts to historic and archaeological resources if (1) the State Historic Preservation Officer (SHPO) identifies no significant resources on or near the site; or (2) the SHPO identifies (or has previously identified) significant historic resources but determines they would not be affected by plant refurbishment, transmission lines, and license-renewal term operations and there are no complaints from the affected public about altered historic character; and (3) if the conditions associated with moderate impacts do not occur." (NRC 1996)

NRC made impacts to historic and archaeological resources a Category 2 issue, because determinations of impacts to historical and archaeological resources are site-specific in nature and the National Historic Preservation Act mandates that impacts must be determined through consultation with the State Historic Preservation Officer.

In DCPP's Final Environmental Statement, the AEC reported that the transmission lines proposed by PG&E would not produce an unreasonable burden on historic sites and building or archaeological sites (Reference 1). The FES does not address the impact of the station on historic and archaeological sites, however, in 1980, an Archeological Resources Management Plan was incorporated into the operating license for DCPP (Reference 2).

As discussed in Section 3.2, PG&E has no refurbishment plans and no refurbishment-related impacts are anticipated. PG&E is not aware of any historic or archaeological resources that have been affected to date by DCPP operations, including operating and maintenance of transmission lines. Because PG&E has no plans to construct additional facilities at DCPP related to license renewal and because any land-disturbing activities that were required would be done under the auspices of PG&E's corporate procedures that insure the protection of cultural resources, PG&E concludes that operation of DCPP over the license renewal term would not impact cultural resources; hence, no mitigation would be warranted.

4.23 REFERENCES

1. U.S. Atomic Energy Commission, "Final Environmental Statement related to operation of Diablo Canyon Power Plant Units 1 and 2," Pacific Gas & Electric Company, Docket Nos. 50-275 and 50-323, May 1973.

2. John Holson, "Archaeological Resources Located on Parcel P, Diablo Canyon, San Luis Obispo County, California," prepared for PG&E, 1986.

ATTACHMENT C

NEW AND SIGNIFICANT INFORMATION FORM

Category 1 / 2

Issue and Discussion: *Enter the Issue number and Description here…….*

A. Interviewee Identification:

i.	Name:	
ii.	Organization:	
iii.	Responsibilities:	
iv.	Telephone:	
v.	Education:	
vi.	Years experience:	
	Here:	
	Other:	

B. Issue-Specific Questions:
For the purpose of these interviews, we are using the term "significant" to mean an environmental impact that is moderate or large.

	CATEGORY 1				
i.	Has this particular issue been of concern at this plant (pick one; if "yes," please explain)? No/Yes				
ii.	How would you characterize the environmental impact associated with this issue at this plant (pick one)?				
		SMALL	MODERATE	LARGE	
iii.	NRC characterized the environmental impact associated with this issue as:	SMALL	MODERATE	LARGE	NA
	Do you agree with the NRC findings for this issue (pick one; if "no," please explain)?No/Yes				
iv.	During the last 10 years or so, have there been any changes in plant operations or plant systems that would affect the plant's impact with respect to this issue?		Yes	No	

v.	Additional comments:

	CATEGORY 2			
i.	Has this particular issue been of concern at this plant (pick one; if "yes," please explain)? No/Yes			
ii.	How would you characterize the environmental impact associated with this issue at this plant (pick one)?			
		SMALL	MODERATE	LARGE
iii.	What documents or individuals would you direct us to for more detailed information on this issue?			
iv.	Additional comments:			

C. General Questions:

i.	Are you aware of any activities or planned activities in the plant area that might have environmental impacts that are similar to, and so cumulative with, plant environmental impacts (if "yes," please explain)? No/Yes
ii.	Are you familiar with the 92 environmental issues that NRC identified as associated with license renewal? Yes If so, are you aware of any new and significant issues that NRC overlooked or findings that are incorrect as applied to this plant (if "yes," please

	explain)? No/Yes
iii.	Have any regulatory agencies or members of the public or public interest groups that you are aware of expressed concern about current or renewed plant operations (if "yes," please explain)? No/Yes

D. Interview Identification:

i.	Date:	
ii.	Location:	DCPP
iii.	Interviewer:	
iv.	Other Attendees:	

Listing of the Issues and Descriptions:

Issue #	Cat #	Description
1	1	Impacts of refurbishment on surface water quality only and if DCPP plans refurbishment in the future.
2	1	Impacts of refurbishment on surface water use. DCPP is not planning a refurbishment. Interview for background only and if DCPP plans refurbishment in the future.
3	1	Altered current patterns at intake and discharge structures.
4	1	Altered salinity gradients.
5	1	Altered thermal stratification of lakes.
6	1	Temperature effects on sediment transport capacity.
7	1	Scouring caused by discharged cooling water.
8	1	Eutrophication
9	1	Discharge of chlorine or other biocides.
10	1	Discharge of sanitary wastes and minor chemical spills.
11	1	Discharge of other metals in waste water.
12	1	Water use conflicts (plants with once-through cooling systems).
13	2	Water use conflicts (plants with cooling ponds or cooling towers using make-up water from a small river with low flow).
14	1	Refurbishment [Aquatic Ecology (for all plants)] Interview for background only and if DCPP plans refurbishment in the future.
15	1	Accumulation of contaminants in sediments or biota.
16	1	Entrainment of phytoplankton and zooplankton
17	1	Cold shock
18	1	Thermal plume barrier to migrating fish
19	1	Distribution of aquatic organisms
20	1	Premature emergence of aquatic insects
21	1	Gas supersaturation (gas bubble disease).
22	1	Low dissolved oxygen in the discharge
23	1	Losses from predation, parasitism, and disease among organisms exposed to sub-lethal stresses
24	1	Stimulation of nuisance organisms (e.g., shipworms)
25	2	Entrainment of fish and shellfish in early life stages
26	2	Impingement of fish and shellfish
27	2	Heat shock
28	1	Entrainment of fish and shellfish in early life stages No interview because DCPP does not have a cooling-tower-based heat dissipation system.
29	1	Impingement of fish and shellfish No interview because DCPP does not have a cooling-tower-based heat dissipation

		system.
30	1	Heat shock No interview because DCPP does not have a cooling-tower-based heat dissipation system.
31	1	Impacts of refurbishment on groundwater use and quality Interview for background only and if DCPP plans refurbishment in the future.
32	1	Ground-water use conflicts (potable and service water; plants that use <100 gpm)
33	2	Ground-water use conflicts (potable and service water, and de-watering; plants that use >100 gpm)
34	2	Ground-water use conflicts (plants using cooling towers withdrawing make-up water from a small river)
35	2	Ground-water use conflicts (Ranney wells) No interview because DCPP does not have Ranney wells.
36	1	Ground-water quality degradation (Ranney wells) No interview because DCPP does not have Ranney wells.
37	1	Ground-water quality degradation (saltwater intrusion)
38	1	Ground-water quality degradation (cooling ponds in salt marshes) No interview because DCPP is not in a salt marsh.
39	2	Ground-water quality degradation (cooling ponds at inland sites)
40	2	Refurbishment impacts [terrestrial resources] Interview for background only and if DCPP plans refurbishment in the future.
41	1	Cooling tower impacts on crops and ornamental vegetation No interview – plant does not use cooling tower for circulating water heat dissipation.
42	1	Cooling tower impacts on native plants No interview – plant does not use cooling tower for circulating water heat dissipation
43	1	Bird collisions with cooling towers No interview – plant does not use cooling tower for circulating water heat dissipation
44	1	Cooling pond impacts on terrestrial resources
45	1	Power line right-of-way management (cutting and herbicide application)
46	1	Bird collision with power lines
47	1	Impacts of electromagnetic fields on flora and fauna (plants, agricultural crops, honeybees, wildlife, livestock)
48	1	Floodplains and wetland on power line right of way
49	2	Threatened or endangered species
50	2	Air quality during refurbishment (non-attainment and maintenance areas) Interview for background only and if DCPP plans refurbishment in the future.

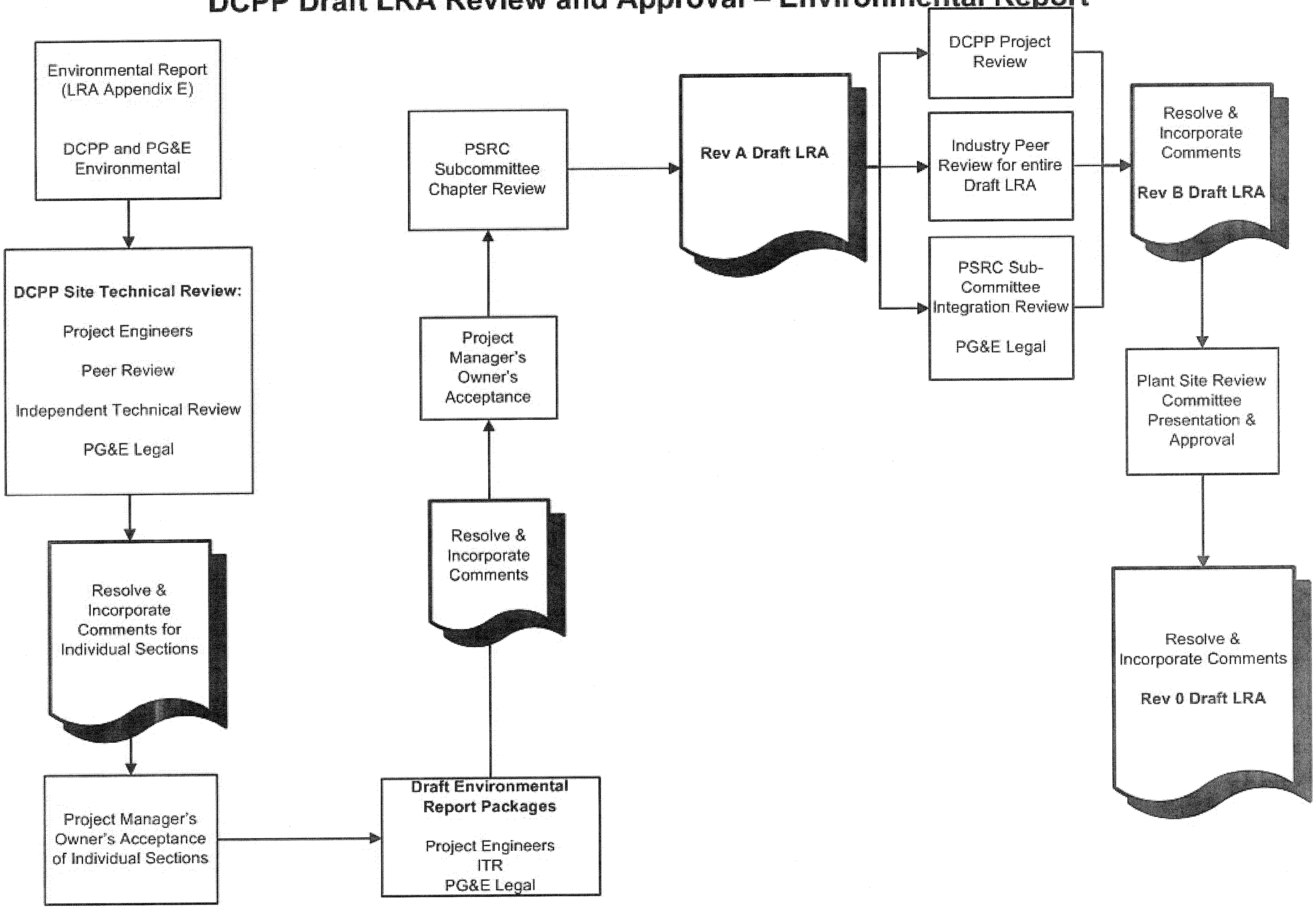
51	1	Air quality effects of transmission lines
52	1	Onsite land use
53	1	Power line right of way [land use]
54	1	Radiation exposures to the public during refurbishment . Interview for background only and if DCPP plans refurbishment in the future.
55	1	Occupational radiation exposures during refurbishment Interview for background only and if DCPP plans refurbishment in the future.
56	1	Microbiological organisms (occupational health) No interview because DCPP does not use cooling towers.
57	2	Microbiological organisms (public health) (plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river)
58	1	Noise
59	2	Electromagnetic fields, acute effects (electric shock)
60	n/a	Electromagnetic fields, chronic effects
61	1	Radiation exposures to public (license renewal term)
62	1	Occupational radiation exposures (license renewal term)
63	2	Housing impacts
64	1	Public services: public safety, social services, and tourism and recreation
65	2	Public services: public utilities
66	2	Public services, education (refurbishment) Interview for background only and if DCPP plans refurbishment in the future.
67	1	Public services, education (license renewal term)
68	2	Offsite land use (refurbishment) . Interview for background only and if DCPP plans refurbishment in the future.
69	2	Offsite land use (license renewal term)
70	2	Public services, transportation
71	2	Historic and archaeological resources
72	1	Aesthetic impacts (refurbishment) . Interview for background only and if DCPP plans refurbishment in the future.
73	1	Aesthetic impacts (license renewal term)
74	1	Aesthetic impacts of transmission lines (license renewal term)
75	1	Design basis accidents
76	2	Severe accidents
77	1	Offsite radiological impacts (individual effects from other than the disposal of spent fuel and high level waste)
78	1	Offsite radiological impacts (collective effects)
79	1	Offsite radiological impacts (spent fuel and high level waste disposal)
80	1	Non-radiological impacts of the uranium fuel cycle

81	1	Low-level waste storage and disposal
82	1	Mixed waste storage and disposal
83	1	On-site spent fuel
84	1	Non-radiological waste
85	1	Transportation
86	1	Radiation doses [decommissioning]
87	1	Waste management [decommissioning]
88	1	Air quality [decommissioning]
89	1	Water quality [decommissioning]
90	1	Ecological resources [decommissioning]
91	1	Socioeconomic impacts [decommissioning]
92	n/a	Environmental justice

ATTACHMENT D

LRFS REVIEW FLOW CHART

Flow Chart 4
DCPP Draft LRA Review and Approval – Environmental Report



ATTACHMENT E

LIST OF AGENCIES CONSULTED

HISTORIC AND ARCHAEOLOGICAL RESOURCES

- Native American Heritage Commission (NAHC)
- California State Historic Preservation Officer
- Native American Tribal Groups

THREATENED OR ENDANGERED SPECIES

- U.S. Fish and Wildlife Service (USFWS)
- National Marine Fisheries Service (NMFS)
- California Department of Fish and Game (DFG)
- State Lands Commission
- Bureau of Land Management

PAM COB Procedure Cover Sheet

Scoping and Screening of Systems, Structures and Components

PAMCOBP - PI-1 – 10/07 - Rev 4

Prepared by: Eric Blocher

Approved by: Paul F Crawley

Date Approved: October 12, 2007

Project Instruction PI-1

Scoping and Screening of Systems, Structures and Components for STARS License Renewal Projects

Revision 4

October 12, 2007

Scoping and Screening of Systems, Structures and Components for STARS License Renewal Projects

Approval Page

Revision	Prepared by:	Reviewed by:	Approved by:
1	Eric A. Blocher	Tony Grenci	Eric A. Blocher
Date	January 28, 2005	February 02, 2005	February 02, 2005
2	Gary D. Warner	Tony Grenci, Philippe Soenen, Arden Aldridge, Al Saunders, Rich Schaller	Eric A. Blocher
Date	Sep. 21, 2005	Oct. 28, 2005	Mar. 10, 2006
3	Gary D. Warner	Jim Johnson	Eric A Blocher
Date	August 24, 2006	August 25, 2006	August 30, 2006
4	Gary D. Warner	Jim Johnson	Eric A. Blocher
Date	October 12, 2007	October 12, 2007	October 12, 2007

Revision Summary

Revision	Required Changes to Achieve Revision	Date
0	Initial Issue	Oct. 08, 2004
1	Incorporated NEI 95-10 Rev. 5 changes for boundary drawings to reflect "components within the scope license renewal". Updated Attachment D System & Structure list to reflect project scoping results. Added additional environments & generic components to PI Attachments. Clarified walkdown documentation requirements.	Feb 02, 2005
2	Rewrite and reformat to incorporate Lessons Learned suggestion (Revision bars not used), NEI 95-10 Rev 6, NUREG-1800 September 2005, and NUREG-1801 September 2005.	Mar 10, 2006
3	Remove attachment E to Topical Report TR-9. Renumber attachment F, G, H and I. Revise bolting comments on new Attachment E. Add reference to Criterion (a)(2) Position Paper.	Aug. 30, 2006
4	Updated section 2.0 references. Revised definitions for COB, USAR, and License Renewal Boundary Diagram. Deleted reference to PAMCOBG-3.	Oct. 12, 2007

TABLE OF CONTENTS

1.0 SCOPE

This instruction provides detailed guidance for implementation of License Renewal (LR) Scoping and Screening activities associated with the Integrated Plant Assessment (IPA) required by 10 CFR 54.

This instruction for LR Scoping and Screening activities is in support of the license renewal applications (LRAs) prepared for the STARS nuclear generating plants.

The STARS plants are all pressurized water reactors (PWRs). This instruction therefore omits details appropriate only to boiling water reactors (BWRs).

1.1 Purpose

This procedure describes the process used by the LR Staff for performing Scoping and Screening.

"Scoping" is the process used to identify those systems, structures and components (SSCs) that fall within the scope of 10 CFR Part 54 (hereafter referred to as "the Rule").

"Screening" is the process used to identify and list those structures and components within the scope of the Rule that require an aging management review.

"Characterization" is the process used to identify and list materials of construction and environments for components that require an aging management review (AMR).

1.2 Applicability

This instruction is to be used by STARS Plant Aging Management Center of Business (PAM COB) staff and plant license renewal project staff for performing, checking, reviewing, or approving of scoping and screening work required in support of each STARS plant's LRA.

The STARS LR Project Manager may designate other individuals to perform checking or review. The Plant LR Project Manager may designate other individuals to perform owner acceptance.

2.0 REFERENCES

1. Title 10, United States Code of Federal Regulations, Energy, Part 54 (10 CFR 54), Requirements for Renewal of Operating Licenses for Nuclear Power Plants.

2. US NRC NUREG-1800. Standard Review Plan for the Review of License *Renewal Applications for Nuclear Power Plants.* Rev. 1, September 2005

3. US NRC NUREG-1801. *Generic Aging Lessons Learned (GALL) Report.* Rev. 1, September 2005

4. Electric Power Research Institute Report EPRI TR-105090. *Guidelines to Implement the License Renewal Technical Requirements of 10 CFR 54 for Integrated Plant Assessments and Time-Limited Aging Analyses.* Licensed Proprietary Material. MDC-Ogden Environmental and Energy Services, Inc., and Gilbert/Commonwealth, Inc., for EPRI, November, 1995.

5. Nuclear Energy Institute Report NEI 95-10. *Industry Guideline for Implementing the Requirements of 10 CFR Part 54 – the License Renewal Rule.* Revision 6 NEI, June 05.

6. DG-1, License Renewal Data Management Tool Users Manual

7. TR-6, Criterion (a)(2) License Renewal Position Paper Series (reference plant specific Position Paper)

8. TR-8, Aging Effect Topical Report Series (reference plant specific Topical Report)

9. TR-9, Plant Systems and Aging Management Programs Topical Report Series (reference plant specific Topical Report)

10. TR-7, Scoping and Screening for Electrical Components Based on Spaces Approach Series (reference plant specific Topical Report)

3.0 DEFINITIONS

3.1 **Aging Management Review (AMR)** – An evaluation of aging effects and means of their qualification or management for the period of extended operation, meeting requirements of 10 CFR 54.21(a). The AMR constitutes the Integrated Plant Assessment (IPA) as defined by 10 CFR 54.3(a). The AMR process includes aging evaluations, AMP evaluations and operating experience reviews.

3.2 **Center of Business (COB) -** Offices maintained for purposes of managing and performing license renewal activities for STARS nuclear generating plants.

3.3 **Component** - A piece of equipment such as a vessel, pipe, pump, valve, relay, or pressure switch, etc. Components of a structure include clearly distinct features such as doors, walls and slabs. Components and materials collectively comprise a system or structure.

3.4 **Commodity Group** - A grouping of like structures or components comprised of similar material and exposed to similar environments that can be dispositioned with a single aging management review. The basis for grouping structures or components within a single commodity group can be characteristics such as similar design, similar materials of construction, similar aging management practices, similar environments, similar service time or similar operating history.

3.5 **Complex Assembly** - A combination of structures and components built to perform a specific function in the plant (e.g., diesel generator starting air skids or heating, ventilating, and air conditioning refrigeration units). These complex assemblies are covered by the Maintenance Rule (10 CFR 65) with regard to performance and condition monitoring programs. This provides reasonable assurance that any pertinent operating experience will be considered appropriately.

3.6 **Current Licensing Basis (CLB)** – Documents and commitments on which a plant license is based. See 10 CFR 54.3(a) for a detailed definition.

3.7 **Function** - The specific processes, conditions, or actions that a system, structure or component was designed to perform.

3.8 **Integrated Plant Assessment (IPA)** – An assessment of effects of nuclear plant aging in support of a license renewal application. The IPA is defined by 10 CFR 54.3(a). For STARS plants the IPA shall be documented with Aging Management Reviews (AMRs) and supporting position papers.

3.9 **Intended Functions** – Functions that define the plant process, condition, or action that must be accomplished in order to perform or support a safety function for responding to a design basis event or to perform or support a specific requirement of one of the regulated events in §54.4(a)(1) through (3). Also see NEI 95-10.

3.10 **LRID** - A unique identifier assigned to a plant system or group of plant systems. This identifier aligns closely with the plant system identifiers.

3.11 **License Renewal Boundary Diagram** – A drawing that identifies major components of a system or structure, which perform or support the identified Intended Function(s). A License Renewal Boundary Diagram can be a mark-up of an existing mechanical system Piping and Instrumentation Diagram (P&ID), Operating Valve Identification Diagram (OVID), or a simple structure location drawing.

3.12 **License Renewal Database Management Tool (LRDMT)** – An electronic database used to populate fields of information during the performance, review and approval of scoping/screening and AMR license renewal activities. This database contains component information necessary to document and evaluate whether systems, structures, and components fall within the scope of 10 CFR 54.4(a)(1) through (3) and to identify those components subject to aging management review.

3.13 **Long Lived** – Those structures or components that are NOT subject to replacement based on a qualified life or specified time period and are anticipated to remain in service for the life of the plant.

3.14 **Passive Components** – Passive components are those that perform their intended function(s) without moving parts or without a change in configuration or properties.

3.15 **Plant Aging Management Center of Business (PAM COB)** – See Center of Business (COB) definition above.

3.16 **Plant License Renewal Project Manager (Plant LR Project Manager)** - The project manager assigned by an individual STARS plant organization to manage the license renewal project for that plant.

3.17 **Plant License Renewal Discipline Lead Engineer (Plant LR Discipline Lead)** - The engineer or specialist assigned by the Plant License Renewal Project Manger to approve license renewal packages.

3.18 **Plant License Renewal Project Staff** - The plant license renewal project manager and subject matter experts (SMEs), and other managers, engineers, data specialists, and support personnel assigned by an individual STARS plant organization to manage and support the license renewal project for that plant.

3.19 **Position Papers/Topical Reports** - Project Position Papers and Topical Reports are technical documents that provide technical details or a technical evaluation (position) that can be used to implement license renewal technical activities. Project Position Papers and Topical Reports provide a consistent and documented interpretation for license renewal activities.

3.20 **Scoping** – The identification of systems, structures, and components that meet the criteria of 10 CFR 54.4(a)(1) through (3).

3.21 **Screening** – The process used to determine, for a system, structure or component within the scope of 10 CFR 54.4(a)(1) through (3), which structures and components require an aging management review.

3.22 **Short Lived** – Those components or structures subject to replacement based on a qualified life or specified time period.

3.23 **Spaces Approach** – Methodology used to evaluate aging effects of all passive, long-lived electrical components within a specified plant space.

3.24 **STARS** - Strategic Teaming And Resource Sharing of nuclear operating plants.

3.25 **STARS License Renewal Discipline Lead Engineer (STARS LR Discipline Lead)** - The engineer or specialist assigned by the STARS License Renewal Project Manger as the lead for the Electrical, Mechanical or Structural group.

3.26 **STARS License Renewal Project Manager (STARS LR Project Manager)** - The project manager assigned to manage license renewal projects for STARS plants from the PAM COB.

3.27 **STARS License Renewal Engineer (STARS LR Engineer)** - The engineer or specialist assigned to License Renewal activities at the PAM COB.

3.28 **STARS License Renewal Project Staff** - The STARS license renewal project manager, the TLAA lead engineer and any TLAA evaluators, and other engineers and specialists assigned to work on STARS license renewal projects.

3.29 **STARS PAM COB Manager** -The manager assigned by the STARS plant organizations to manage PAM COB license renewal business.

3.30 **Subject Matter Expert (SME)** - A technical representative responsible for and familiar with a system, structure, component, analysis, program, or other technical issue; and assigned by the individual plant organization to provide support for the plant license renewal project.

3.31 **Structure** – An arrangement of interconnected members that is capable of supporting its own weight and externally applied loads. A structure supports, encloses and/or protects electrical and mechanical systems so that these systems can perform their intended functions(s).

3.32 **Sub-component** – A part or subassembly forming part of a component.

3.33 **Support System** - A system whose support is necessary for another system to perform its intended function(s).

3.34 **System** – A group of components united by some interaction or interdependence, performing many duties but functioning as an integrated unit

3.35 **The Rule** –10 CFR Part 54 – Requirements for Renewal of Operating Licenses for Nuclear Power Plants.

3.36 **Updated Safety Analysis Report (USAR)** – The most recent safety analysis report (SAR) as required by 10 CFR 50.71. Also known as Updated Final Safety Analysis Report (UFSAR) or Final Safety Analysis Report Update (FSAR Update).

4.0 INSTRUCTIONS

4.1 General

The License Renewal Data Management Tool (LRDMT) is used, in association with this instruction, to populate fields of information to produce the License Renewal System and Structure Scoping Report (Scoping Report) (Attachment A) and the License Renewal Component Summary Screening Report (Screening Report) (Attachment B). Control and use of the LRDMT is described in desktop guide DG-1, "License Renewal Data Management Tool Users Manual".

Current licensing basis (CLB) documents shall be utilized when determining whether a system, structure or component falls within the scope of 10 CFR 54.4(a)(1) through (3). CLB documents include documents such as the Updated Safety Analysis Report (USAR), site Technical Specifications, Safety Evaluation Reports (SERs), and NRC orders.

Reference documents or databases such as licensed operator training plans, plant equipment list database, or Maintenance Rule Database may also be used to assist in system or structure scoping. However, reference documents or databases that are not official CLB documents cannot be the sole basis for deciding whether a system or structure falls within the scope of 10 CFR 54.4(a)(1) through (3).

A simplified diagram of the license renewal scoping and screening process is provided in Attachment D.

The following subtasks are approximately in order of occurrence, but may be performed in any order that available information and other resources permit.

4.2 Scoping of Systems and Structures

4.2.1 General

Scoping is performed using the LRIDs (see reference 9) assigned to the plant systems or structures or a group of systems or structures.

The LRDMT is used to create a Scoping Report (Attachment A) on a system specific or structure specific basis.

The LRDMT assigns a unique number to each Scoping Report using the following format.

<*Plant Id*>-SCO-<*LRID*>-Rev N-<*Plant System Name*>

- <*Plant Id*> denotes the Plant Id.

- *<LRID>* denotes the LRID of the LR system being evaluated, as defined in reference 9.

- *<Plant System Name>* denotes the system of the LR system being evaluated, as defined in reference 9.

4.2.2 Responsibilities

STARS LR Engineer

- Perform the Scoping for assigned LRIDs.

- Notify the STARS LR Discipline Lead that Scoping Reports are ready for checking.

- Receive, compile and reconcile comments.

STARS LR Discipline Lead

- Check Scoping Reports.

Plant LR Discipline Lead

- Approve the Scoping Report.

Plant LR Project Manager

- Owner Approve Scoping Reports.

4.2.3 Scoping

Perform the following using the LRDMT Scoping module to complete the Scoping of an LRID.

4.2.3.1 Select the LRID assigned to a system or structure.

4.2.3.2 Use the CLB documents and reference documents to identify all functions that the system or structure is required to accomplish.

4.2.3.3 At the Scoping Question Tab, answer each of the following scoping questions, using the information found in CLB documents and reference documents, to determine whether the system or structure falls within the scope of 10 CFR 54.4(a)(1) through (3).

(1) Is the system or structure safety-related, ensuring the integrity of the reactor coolant pressure boundary?

(2) Is the system or structure safety-related, providing capability to shutdown the reactor and maintain it in a safe shutdown condition?

(3) Is the system or structure safety-related, providing capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to the guidelines in 10 CFR 50.34(a)(1), 50.67(b)(2), or 100.11 as applicable?

(4) Does failure of the non-safety-related system, structure, or component prevent satisfactory accomplishment of any of the three safety-related functions listed in questions (1) through (3)?

(5) Is the system or structure relied on in safety analysis or plant evaluation to perform a function that demonstrates compliance with 10 CFR 50.48, Fire Protection (FP)?

(6) Is the system or structure relied on in safety analysis or plant evaluation to perform a function to demonstrate compliance with 10 CFR 50.49, Environmental Qualification (EQ)

(7) Is the system or structure relied on in safety analysis or plant evaluation to perform a function that demonstrates compliance with 10 CFR 50.61, Pressurized Thermal Shock (PTS)?

(8) Is the system or structure relied on in safety analysis or plant evaluation to perform a function that demonstrates compliance with 10 CFR 50.62, Anticipated Transient Without Scram (ATWS)?

(9) Is the system or structure relied on in safety analysis or plant evaluation to perform a function that demonstrates compliance with 10 CFR 50.63, Station Blackout (SBO)?

4.2.3.4 Responses to questions (1) through (3) are found by referring to CLB documents such as the USAR and/or the Technical Specifications. Information contained in non-CLB documents (e.g. Maintenance Rule Data Base) may be used to assist this process, but must be confirmed by reference to CLB documents.

4.2.3.5 Responses to questions (4) through (9) can typically be determined by referring to the Position Papers and applicable CLB documents referenced therein.

4.2.3.6 If system or structure is not described in any CLB documents, the following generic statement shall be included in the comment section of the LRDMT.

"The system/structure is not credited in any plant current licensing bases or in any plant-specific compliance to Fire Protection, EQ, ATWS, PTS, and SBO."

Note:

Unless a CLB document clearly references the need for a specific structure to satisfy any of the scoping questions, structures are not to be arbitrarily included in the scope of 10 CFR 54.4(a)(1) through (3) based simply upon the fact that the structure encloses or covers a component or system within the scope of the Rule.

4.2.3.7 If the answer to scoping questions 1-9 are all "No", the LRDMT will automatically place a "No" in the question "Does the system fall within the scope of 10 CFR Part 54?" Perform the following:

- Complete the "System Description" and "System Function" fields per Step 4.2.3.10 and 4.2.3.11
- If components have been realigned review section 4.4.5 to determine whether a boundary drawing showing the realigned components is required. Describe the realignment and the basis for it in the "System Description" field.
- Enter the reference documents used to perform the scoping in the Ref Documents Tab. Only references that have a direct use in the scoping package shall be entered.
- Document the critical thinking that supports the out-of-scope conclusion in the Comments/Approvals Tab "General Comments" field
- Enter a summary of the revision in the Comments/Approvals Tab "Rev Summary" field.

- Check the “Prep” check box on the LRDMT Approvals Tab.

- Notify the STARS LR Discipline Lead or the designated checker that the Scoping Report is ready for checking.

4.2.3.8 If the answer to any of the nine scooping questions is “Yes”, the LRDMT will automatically place a “Yes” in the question “Does the system fall within the scope of 10CFR Part 54?”

4.2.3.9 Use the Intended Function Tab to identify the Intended Functions that are the basis for including the system or structure within the scope of the Rule.

- The “Intended Functions” are those functions that satisfy any of the scoping questions.

- Repeat the function when a function satisfies more than one scoping question.

- Include the following phrases as appropriate for mechanical intended functions in response to questions 1 through 3 (bold is only used for demonstration purposes):
    - **…**to provide for the **maintenance of vital auxiliaries** to support the critical safety functions.
    - **…**to support the critical safety function of **reactivity control.**
    - **…**to support the critical safety function of **inventory and pressure control.**
    - **…**to support the critical safety function of **heat removal.**
    - **…**to support the critical safety function of **containment integrity**
    - **…**to support the critical safety function of **containment atmosphere control**
    - **…**to support the critical safety function of preventing an **indirect radioactive release**

  If applicable, combine more than one phrase into the same intended function.

4.2.3.10 Enter the system description in the Sys Description/Function Tab “System Description” field. This summary shall be to the level of detail that can be used in the NRC Safety Evaluation Report (SER) and include the following:

- Purpose of the system or structure.
- Boundary of the system or structure within the scope of the Rule.

4.2.3.11. Enter the system function summary in the Sys Description/Function Tab “System Function” field. This summary shall include the following:

- A summary of the system or structure intended functions.
- The conclusion statements for question 1 through 9 that are noted in the following steps:

4.2.3.12 If Questions 1, 2 and/or 3 are Yes, enter the following in the “System Function” field.

“The <*LRID name*> is within the scope of license renewal based on the criteria of 10 CFR 54.4a(1).”

4.2.3.13 If Question 4 is Yes, enter the following in the “System Function” field.

“Portions of the <*LRID name*> are in scope as non-safety affecting safety-related components based on the criterion of 10 CFR 54.4(a)(2).”

4.2.3.14 If Questions 5, 6, 7, 8, and/or 9 are Yes, enter the appropriate portions of the following in the “System Function” field.

“Portions of the <*LRID name*> are required to support fire protection, environmental qualification, pressurized thermal shock, ATWS, and/or station blackout based on criteria of 10 CFR 54.4(a)(3).”

4.2.3.15 Enter the primary USAR references used to create the system description in the “USAR Reference” field. These references will be included in the license renewal application.

4.2.3.16 For those systems or structures that fall within the scope of 10 CFR 54.4(a)(1), determine the support systems necessary for the evaluated system to complete the "Intended Functions".

4.2.3.17 For systems that fall within the scope of 10 CFR 54.4(a)(3), only identify support systems that are explicitly called out in the CLB.

4.2.3.18 Enter only the support systems that support the intended functions using the Support Systems Tab.

4.2.3.19 Use the Ref Documents Tab to document the references used to perform the system scoping. Only references that have a direct use in the scoping package shall be entered.

4.2.3.20 Use the Comment/Approvals Tab to record any comments pertinent to the logic used in scoping a system or structure in the "General Comments" field.

4.2.3.21 Upon completing the Scoping, the responsible STARS LR Engineer shall use the Comments/Approvals Tab to:

- Enter a summary of the revision in the "Rev Summary" field.
- Check the "Prep" check box.

4.3 Boundary Drawings

4.3.1 General

LR Boundary Diagrams are not required for those systems that are not within the scope of the Rule.

Electrical & Instrumentation Boundary Drawings
LR Boundary Diagrams are not required for those systems within the scope of the Rule that are primarily comprised of instrumentation and electrical components. Electrical License Renewal drawings shall be created that show the major electrical AC and DC buses and offsite power restoration path by highlighting in green the applicable electrical one line diagrams. The numbering of the electrical drawings shall be in accordance with section 4.3.3.4.

Structural Boundary Drawings
LR Boundary Diagrams are not required for those individual structures within the scope of the Rule. A Site Plan License Renewal drawing

shall be created that identifies the structures in the scope of the Rule with green highlight. The numbering of the Site Plan shall be in accordance with section 4.3.3.4.

4.3.2 Responsibilities

STARS LR Engineer

- Prepare the Boundary Drawings for assigned LRID.
- Notify the STARS LR Discipline Lead that Boundary Drawings are ready for checking.
- Receive, compile and reconcile checking comments.

STARS LR Discipline Lead

- Check Boundary Drawings.

4.3.3 Preparing Boundary Drawings

For each mechanical system that falls within the scope of 10 CFR 54.4(a)(1) through (3), create License Renewal Boundary Diagram(s) as follows.

4.3.3.1 Review the intended functions of the system or structure and identify those portions of the system or structure that are necessary to accomplish the intended functions.

4.3.3.2 Highlight in green those components that are within the scope of 10 CFR 54.4(a)(1) and (3).

4.3.3.3 Highlight in red those components that are within the scope of 10 CFR 54.4(a)(2). See reference 7 for plant specific scoping guidance for criterion (a)(2).

4.3.3.4 Assign unique license renewal drawing number(s) designated using the following format

LR-*Plant Id*-*<LRID>*-*<XXXX>*

- *<Plant Id>* denotes the Plant Id.
- *<LRID>* denotes the LRID of the LR system being evaluated, as defined in reference 9.
- *<XXXX>* denotes the existing drawing number(s), including sheet number, on which the LR Boundary

Diagram is based. (e.g. if the base drawing is M-35, Sheet 2, and then replace <XXXX> with “M-35-2.”)

4.3.3.5 Add the license renewal Boundary Diagram number(s) to the Reference Documents Tab in the LRDMT.

Note:

If a system or structure falling within the scope of 10 CFR 54.4(a)(1) through (3) is found not to have an associated P&ID or structural location drawing which can be marked-up to create an LR Boundary Diagram, then a simple sketch of the system or structure may be created and the LR Boundary Diagram may be developed from that simple sketch.

Assignment of a unique number to any such created sketches and the associated LR Boundary Diagrams will be coordinated with STARS License Renewal Project Manager.

4.4 Screening of System Components and Structures

4.4.1 General

Screening of system components and structures is to be done using the LRIDs assigned to the plant systems or structures or a group of systems or structures (see reference 9).

The LRDMT is used to create a Screening Report (Attachment B) on a system specific or structure specific basis. The LRDMT assigns a unique number to each Screening Report using the following format.

<Plant Id>-SCR-*<LRID>*-Rev N-*<Plant System Name>*

- *<Plant Id> denotes the Plant Id.*
- *<LRID>* denotes the LRID of the LR system being evaluated, as defined in reference 9.

Electrical components will not be screened with the individual system. All electrical components as listed in reference 10, “Scoping and Screening for Electrical Components Based on Spaces Approach” will be assigned to the Electrical Component LRID "ELEC". These components will be scoped and screened as a group using the process described in the position paper

4.4.2 Responsibilities

STARS LR Engineer

- Perform the Screening for assigned LRID.
- Notify the STARS LR Discipline Lead that Screening Reports are ready for checking.
- Receive, compile and reconcile comments.

STARS LR Discipline Lead

- Check Screening Reports.

Plant LR Discipline Lead

- Approve the Screening Report.

Plant LR Project Manager

- Owner Accept Screening Reports.

4.4.3 Assign System Components

Components in the LRDMT shall be assigned to the appropriate LRID.

LRID Boundaries are determined based on associated engineering drawings (e.g. P&IDs, OVIDs), which depict the system's principal functional components.

For non-grouped systems, the LRID is the plant system designator. For grouped systems, the LRID is the assigned group designator (see reference 9).

Perform the following using the LRDMT Component Screening module to scope components for an assigned LRID.

4.4.3.1 Identify and obtain the P&IDs or OVIDs, which show the system being scoped.

4.4.3.2 Review the drawing(s) and determine which components on the drawing(s) comprise the system to be evaluated.

4.4.3.3 Identify the component designators, which are assigned to the components of the system. The component designators will normally be a unique character plant system code.

4.4.3.4 Use the LRDMT to electronically search for the component shown on LR Boundary Diagram(s).

Note:

The LRDMT allows searching, grouping and sorting of components by various data fields. The evaluator should use searches, groupings and sorting that are appropriate to locate and identify all of the primary components and associated supporting or sub-components that are related to the system being evaluated.

4.4.3.5 If the component is found perform the following:

- Enter the LRID in the "LRID" field.
- Determine if the component is within the scoping boundary previously identified and check the "LR" check box to indicate that the component is within the scope of the Rule.

4.4.3.6 If the component is not found perform the following:

- Add the component to the LRDMT.
- Assign the component to the LRID being evaluated.
- Determine if the component is within the scoping boundary previously identified and check the "LR" check box to indicate that the component is within the scope of the Rule

Note:

Do not add components, such as supports and tubing, which are evaluated as commodities, by component number.

Add at least one record for this type of component as a specific component or generic component.

4.4.3.7 If the LRID for component records has already been assigned perform the following:

- If the assigned LRID is that of the system currently being evaluated, then accept the record's LRID field as-is.

- If the assigned LRID is a different LRID from the one currently being evaluated, review with the responsible STARS LR Engineer the basis for the earlier assignment and together determine to which LRID the component should be assigned.

4.4.3.8 Using the generic components listed in Attachment E, perform the following:

- Add generic components missing from the LRDMT that apply to each LRID.

- Assign the component to the LRID being evaluated.

- Determine if the component is within the scoping boundary previously identified and check the "LR" check box to indicate that the component is within the scope of the Rule.

4.4.3.9 Use the LRDMT to search for components within the system being evaluated that have not been assigned an LRID and perform the following:

- Assign the component to the LRID being evaluated.

- Determine if the component is within the scoping boundary previously identified and check the "LR" check box to indicate that the component is within the scope of the Rule.

Caution:

The STARS LR Engineer must be cognizant of the effects of moving in-scope components from one system to another.

System intended functions and boundary diagrams may be impacted by such changes.

Fully evaluate the impact of moving components on both the sending and the receiving systems before recommending that the change be made.

4.4.4 Assign Structural Components

Perform the following using the LRDMT Component Screening module to assign structural components to an LRID.

4.4.4.1 Identify and obtain the structural location drawings, which show the structure being scoped.

4.4.4.2 Review the drawing(s) and determine which components on the drawing(s) comprise the structure to be evaluated.

4.4.4.3 Use the LRDMT to electronically search for the structural component for the structures.

4.4.4.4 If structural components are found, perform the following for each structural component:

- Enter the LRID in the “LRID” field.
- Determine if the structural component is within the scope of the Rule and, if so, check the “LR” check box to indicate that the component is within the scope of the Rule.
- With the concurrence of the STARS LR Discipline Lead, generic components may be added to the LRDMT to represent a Commodity Group. Select and enter the generic component using Attachment E. Replace the individual components with the generic component by placing “REMOV” in the LRID field and a note in the comments field of the individual component to explain the removal.

4.4.4.5 If structural components are not found, use the generic components listed in Attachment E to add those components missing from the LRDMT to each structural LRID.

- Enter the LRID in the “LRID” field.
- Determine if the structural component is within the scope of the Rule and check the “LR” check box to indicate that the component is within the scope of the Rule.

4.4.4.6 At some point during the component assignment process for structures it may be prudent to perform a walkdown to ensure that all components have been captured in the LRDMT. Document the walkdown by completing the Walkdown

Documentation Form, Attachment C, or by using other walkdown documentation acceptable to the Plant LR Project Manager.

4.4.5 Component Realigning

In Section 2.1.3.1 of NUREG-1800 Standard Review Plan for License Renewal (Ref. 2) the NRC has indicated its acceptance of the current industry practice of realigning components from their normally assigned system to a different system for purposes of license renewal evaluation. Examples of this practice are the following:

- Grouping containment isolation valves from various systems into a single system for license renewal evaluation.
- Realigning safety-related fuses or breakers from a non-safety-related instrumentation and control system to a safety-related power system, when the sole basis for the fuses' safety-related classification is that it is required to provide highly reliable electrical separation between a safety-related power circuit and a non-safety-related load.

The following instructions provide guidance for when to consider and how to document component realignments.

4.4.5.1 Consider realignment of components for situations similar to the examples presented above.

4.4.5.2 Realignment of components should be considered when all but a few of the components in the system being evaluated are clearly outside the scope of the Rule.

Note:

The term "few" is NOT procedurally quantified. However, if more than 10% of the evaluated LRID's major components are within the scope of the Rule, then realignment should not be implemented.

4.4.5.3 If the affected component is being realigned to an LRID, which has already been scoped, obtain concurrence of the STARS LR Discipline Lead and the STARS LR Project Manager and agreement of the affected STARS LR Engineer prior to implementing the realignment.

4.4.5.4 Realignment of a component to an already approved LRID scoping package will require revision of the previously approved LRID scoping package.

4.4.5.5 Document component realignment as follows:

- Enter the following comment into the component "Comment" field

  "Realigned from <*LRID*>."

- Create a LR Boundary Realignment Sketch to identify which portions of the system have been realigned. Include sufficient information on the sketch that a reviewer can clearly understand what components were realigned and to what LRID they were realigned.

Note:

A LR Boundary Realignment Sketch is not applicable for re-aligned components that normally do not appear on a boundary drawing (e.g., fuses, supports, etc.).

In these instances, the comment field provides sufficient documentation of what component was realigned.

- Enter a brief description of what components were realigned and why in the "System Description" field on the Scoping module Sys Description/Function Tab for the LRID to which the components are realigned (The description is not required to itemize the components, but it should describe them in sufficient detail for an independent reviewer to understand which components are affected).

Note:

The description provided above is intended to notify the STARS LR Engineer of the LRID receiving the realigned component.

It is expected that the description will be used by that STARS LR Engineer during evaluation of the LRID to which the component is realigned.

If the receiving LRID has already been evaluated, then this activity must be approved by the STARS LR Discipline Lead responsible for the LRID.

4.4.6 Component Screening and Characterization

4.4.6.1 For each component within the scope of the Rule perform the following:

- Use Appendix B to NEI 95-10 to determine whether the component is passive. If the component is passive check the Passive Check Box.
- For each passive component determine if the component is long lived. If the component is not long lived (short lived) uncheck "LL" check box. Enter, in the "Comments" field, the maintenance activity that is used to replace the component. If it cannot be determined whether a component is long lived, conservatively assume that the component is long lived.

Note:

Attachment F identifies certain short-lived consumables and components that do not require an aging management review; short lived consumables are not required to be listed on the LR Screening Report.

4.4.6.2 For each component that is passive and long lived perform the following:

- Select the appropriate component passive intended function code in the "Func 1" field (See Attachment G).
- If the component has more than one passive intended function, then select each of the passive intended functions in the "Func 2-4" fields. If more than four passive intended functions are required for a component, duplicate the component Id and list the additional intended functions on the duplicated component Id line "Func 1-4" fields.
- Select the internal environment to which the component type is exposed in the "Env Int" field. Internal Environments are identified on Attachment H.
- Select the external environment to which the component type is exposed in the "Env Ext field. External Environments are identified on Attachment H.

- Select the materials of construction in the "Mat" field. Common materials used in fabrication of the component such as carbon steel, cast iron, copper, brass, and elastomers should be identified. Materials should be identified consistent with the level of detail of the aging management review line items in NUREG-1801.

- Enter the reference document that was used to identify the materials of construction in the "Mat Ref" field. Plant walkdowns to verify materials of construction can be referenced if they are documented (see Attachment C) and included as part of the supporting documentation.

Note:

Only components within the scope of the Rule that perform an intended function without moving parts or without a change in configuration or properties are subject to an Aging Management Review. Thus, only component **passive** function(s) are listed in Attachment G and on the Screening Report.

Active component functions are not listed. If a component within the scope of the Rule performs no passive functions, the "Passive" check box is not checked and the "Func 1-4" fields are "N/A."

4.4.6.3 Upon completion of screening of all the components associated with an LRID, the responsible STARS LR Engineer shall perform the following using the Approval/Reports Tab:

- Enter a summary of the revision in the "Rev Summary" field.

- Check the "Prep" check box.

4.4.6.4 Assemble the Scoping and Screening package for checking. The Scoping and Screening package shall consist of the following:

- The Scoping Report created from the LRDMT.

- The Screening Report created from the LRDMT.

- The Component Report created from the LRDMT

- Boundary Drawings.

- Reference documents used to prepare the Scoping and Screening package are optional and should be provided to simplify checking activities.

4.4.6.5 Forward the Scoping and Screening package to the STARS LR Discipline Lead or the designated checker for checking.

4.5 Scoping and Screening Package Checking and Approval

4.5.1 Scoping and Screening Package Checking

4.5.1.1 The Checker is responsible, as a minimum, to review assigned package(s) for conformance to the following criteria, and the Checker's signature confirms reasonable assurance that these criteria are satisfied:

- The checked package is in the proper format and conforms to applicable Project Instructions and Desktop Guides.

- The information contained in the scoping package is technically correct, and the basis for scoping conclusions is adequately referenced and/or justified.

- Boundary diagram(s) are prepared as required and properly indicate realigned components and components within the scope of 10 CFR 54.4(a)(1) through (3).

- Screening results are technically correct and are consistent with what is shown on the boundary diagram(s).

- Internal and external environments have been identified consistent with plant configuration. Materials of construction have been identified consistent with the level of detail in NUREG-1801 and properly referenced.

4.5.1.2 The Checker shall forward any comments to the responsible STARS LR Engineer for resolution.

4.5.1.3 The Checker upon completion of the checking of the Scoping and Screening Package shall perform the following.

- Check the "Cked" check box on the LRDMT Scoping Approval/Reports Tab.

- Check the "Cked" check box on the LRDMT Screening Approval/Reports Tab.

- Notify the Plant LR Discipline Lead that the Scoping and Screening Package is ready for approval.

- Forward copies for the Boundary drawings to the Plant LR Discipline Lead.

4.5.2 Scoping and Screening Package Approval

4.5.2.1 Plant LR Discipline Lead shall review the scoping and screening package for technical accuracy and completeness and approve the Scoping and Screening package. Approval indicates the package is ready for Plant PM review for owner acceptance.

4.5.2.2 The Plant LR Discipline Lead shall forward any comments to the responsible STARS LR Engineer for resolution. Approval shall not be given until the Plant LR Discipline Lead comments are dispositioned.

4.5.2.3 The Plant LR Discipline Lead, upon approving the Scoping and Screening Package, shall:

- Check the "App" check box on the LRDMT Scoping Approval/Reports Tab.

- Check the "App" check box on the LRDMT Screening Approval/Reports Tab.

- Notify the Plant LR Project Manager that the Scoping and Screening Package is ready for Owner Approval.

4.5.3 Scoping and Screening Owner Acceptance

4.5.3.1 The Plant LR Project Manager shall review and Owner Approve the Scoping and Screening Package.

4.5.3.2 The Plant LR Project Manager shall forward any comments to the responsible STARS LR Engineer for resolution.

4.5.3.3 The Plant LR Project Manager, upon approving the Scoping and Screening Package, shall.

- Check the "Own App" check box on the LRDMT Scoping Approval/Reports Tab.

- Check the "Own App" check box on the LRDMT Screening Approval/Reports Tab.

4.6 Data Records

4.6.1 A Screening Report (Attachment B) will NOT be used to record data for components of systems and structures which are determined not to be within the scope 10 CFR 54.

4.6.2 Adding generic structural and system components is not required for those systems not within the scope 10 CFR 54.

4.6.3 LR Boundary Diagrams are not required for those systems that are not within the scope of the Rule.

4.7 Reporting of Existing Problems Found During the Work

During the Scoping and Screening work a current-term deficiency may be found in Plants' CLB documents, plant equipment list database or other referenced sources. Examples of current-term deficiencies include:

- An error, either typographical or otherwise, in CLB documentation such as the USAR.
- An incorrect or deficient entry in the Plant equipment list.
- A physical plant or equipment defect.

4.7.1 The STARS LR Engineer is responsible to clearly document the problem(s) and to provide timely notification of the problem(s) to the Plant LR Discipline Lead.

4.7.2 Problems with incorrect or deficient plant component data in the LRDMT shall be documented as follows:

4.7.2.1 Check the "Pbl" check box for the component record.

4.7.2.2 Enter a comment in the "Comment" field that explains the nature of the problem.

4.7.2.3 Create a Problem Component Report and forward it to the Plant LR Discipline Lead. Include a copy with the Scoping and Screening Package.

4.7.3 Upon discovery of an apparent current licensing basis issue, Plant License Renewal project staff shall ensure the issue is entered into the plant's corrective action program.

4.8 Revising System Scoping and Screening Packages

After individual Scoping and Screening packages for systems, structures and components are approved, it is anticipated that a "clean-up" activity will be performed to ensure consistency of the completed packages, the boundary diagrams and the LRDMT.

4.8.1 The person identifying the need for the change shall contact the STARS LR Engineer responsible for the Scoping and Screening package.

4.8.2 The STARS LR Engineer shall send an e-mail explaining the change to the STARS LR Project Manager with a copy to the STARS LR Discipline Lead.

4.8.3 The STARS LR Project Manager will notify the Plant LR Project Manager of the proposed change and, with concurrence of the Plant LR Project Manager, will provide approval to make the proposed change.

4.8.4 The STARS LR Discipline Lead upon approval of the change will open a new revision of the Scoping or Screening LRID in the LRDMT

4.8.5 The STARS LR Engineer shall make the change to the Scoping or Screening LRID in the LRDMT, document the change in the "Comment" field and Summarize the change in the "Rev Summary" field.

4.8.6 Before the Aging Evaluation is approved for a given LRID the STARS LR Discipline Lead will ensure that any revised Scoping or Screening package is checked, approved and owner accepted.

Attachment A:
License Renewal System and Structure Scoping Report

License Renewal System and Structure Scoping Report
License Renewal Id No. *<LRID>*

<Plant System Name>

Document No	**<Plant>-SCO-*<LRID>*-Rev 1-*<Plant System Name>***
Station and Unit	***<Station Name>***
Related Plant System(s)	***<Related Plant System Nos>***
Scope Determination	**In Scope**

Approvals/Revisions:

Rev	Date	Revision	Preparer	Checker	Approver	Owner
0		Initial issue				

License Renewal System and Structure Scoping Report
License Renewal Id No. *<LRID>*

<Plant System Name>

System Description:

This summary shall be to the level of detail that can be used in the NRC Safety Evaluation Report (SER) and shall include the purpose of the system or structure and a summary of the boundaries of the system or structure.

Example:
The purpose of the Emergency Diesel Fuel Oil system is to provide fuel oil for the emergency diesel engine. The system consists of an underground storage tank with a transfer pump, day tank, strainers, filters, piping, and valves for each emergency diesel engine.

System Function Summary:
Summarize the system or structure intended functions and include the following conclusion statements.

"The *<LRID name>* is within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1)."

"Portions of the *<LRID name>* are in scope as non-safety affecting safety-related components based on criteria of 10 CFR 54.4(a)(2)."

"Portions of the *<LRID name>* are required to support fire protection, environmental qualification, pressure thermal shock, ATWS, and/or station blackout based on criteria of 10 CFR 54.4(a)(3)."

Example:
The Emergency Diesel Fuel Oil system provides on-site storage and delivery of fuel oil as required for emergency diesel operation during design basis events.

The Emergency Diesel Fuel Oil system is within the scope of license renewal based on the criterion of 10CFR54.4(a)(1). Portions are in scope as non-safety-related affecting safety-related components based on the criterion of 10CFR54.4(a)(2). Portions of the Emergency Diesel Fuel Oil system are required to support fire protection requirements based on the criterion of 10CFR54.4(a)(3).

USAR References:

List the USAR References used to develop the system description and the system function summaries.

License Renewal System and Structure Scoping Report
License Renewal Id No. *<LRID>*

<Plant System Name>

Scope Determination

Does the system or structure fall within the scope of 10CFR Part 54? **Yes/No**
(If the answer to any of the questions listed in (1-9) is "Yes" then the system or structure falls within the scope of 10CFR54.)

Scoping Questions

1.) Is the system or structure safety-related ensuring the integrity of the reactor coolant boundary? 10CFR54.4(a)(1)(i) **Yes/No**

2.) Is the system safety-related providing capability to shutdown the reactor and maintain it in a safe shutdown condition? 10CFR 54.4(a)(1)(ii) **Yes/No**

3.) Is the system or structure safety-related providing capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to 10 CFR Part 50.34(a)(1), 50.67(b)(2), or 100.11 guidelines? 10CFR54.4(a)(1)(iii) **Yes/No**

4.) Does failure of the non-safety-related system, structure or components prevent satisfactory accomplishment of any of the three safety-related functions listed above? 10 CFR 54.4(a)(2) **Yes/No**

5.) Is the system or structure relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC's regulations for Fire Protection 10CFR50.48? 10CFR54.4(a)(3) **Yes/No**

6.) Is the system or structure relied on in safety analyses or plant evaluations to perform a function to demonstrate compliance with NRC's regulations for Environmental Qualification 10CFR50.49? 10CFR54.4(a)(3) **Yes/No**

7.) Is the system or structure relied upon to demonstrate compliance with Pressure Thermal Shock 10CFR 50.61? 10 CFR 54.4(a)(3) **Yes/No**

8.) Is the system or structure relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC's regulations for Anticipated Transients Without Scram ATWS) 10CFR50.62? 10CFR54.4(a)(3) **Yes/No**

9.) Is the system or structure relied on in safety analysis or plant evaluation to perform a function that demonstrates compliance with NRC's regulations for Station Blackout 10CFR50.63? 10CFR54.4(a)(3) **Yes/No**

License Renewal System and Structure Scoping Report
License Renewal Id No. *<LRID>*

<Plant System Name>

Identification of System Functions:

Question No. **Intended?** **Function Description/Comments**

<Q No> **<***Yes>* **Function Desc** *<Function Description>*

Comments

Reference Documents:

Type	***No. Or Section***	***Rev***	***Title***
<Document Type>	*<Doc No>*	<Rev>-	*<Document Title>*

Identification of Support Systems:

Support LRId No: *<LRID>* *<Plant System Name*

Comments:

Comments:

<*Comments pertinent to the logic used in scoping a system or structure.>*

Printed ***<Date>*** **Page 4 of 4**

Doc. No <Plant>-SCO-<*LRID*>-Rev 1-<*Plant System Name*>

Attachment B:
Component Summary Screening Report

License Renewal Component Summary Screening Summary Report

License Renewal Id No. <LRID>

<Plant System Name>

Document No: **<Plant>-SCR-<*LRID*>-Rev 0-<*Plant System Name*>**

Station and Unit: **<STARS Plant Name>**

Related Plant System(s): ***<Plant System Nos>***

Approvals/Revisions:

Rev	Date	Revision	Preparer	Checker	Approver	Checker

License Renewal Component Summary Screening Summary Report

License Renewal Id No. <LRID>

<Plant System Name>

Component **PIPING LINE**

Qty	LR	Passive	Func 1	Func 2	Func 3	Func 4	LL	Cmp Int Env	Cmp Ext Env	Cmp Mat	Ref Doc No
2	Yes	Yes	NA	NA	NA	NA	Yes	Demineralized Water (CE001)	Plant Indoor Air (CE011)	Carbon Steel (CM001)	Spec M67

Component **VALVE**

Qty	LR	Passive	Func 1	Func 2	Func 3	Func 4	LL	Cmp Int Env	Cmp Ext Env	Cmp Mat	Ref Doc No
4	Yes	Yes	FM01	NA	NA	NA	Yes	Demineralized Water (CE001)	Plant Indoor Air (CE011)	Carbon Steel (CM001)	Spec M67
1	No	No					No				

DATA SHOWN IS FOR ILLUSTRATION ONLY

License Renewal Component Summary Screening Summary Report

License Renewal Id No. <LRID>

<Plant System Name>

Problem Components:

Cmp No	Cmp Name	Cmp Type	Comments	Resp. Eng.
ABV0006	SG D PT-4 ISO	SG D PT-4 ISO	Component can not be found on P&ID	gdwarner

DATA SHOWN IS FOR ILLUSTRATION ONLY

License Renewal Component Summary Screening Summary Report

License Renewal Id No. <LRID>

<Plant System Name>

Component Intended Function List

FE01	Electrical Continuity	FS01	Structural Support	FM01	Pressure Boundary
FE02	Insulate (electrical)	FS02	Fire Barrier	FM02	Throttle
		FS03	Shelter, Protection	FM03	Filter
		FS04	Flood Barrier	FM04	Heat Transfer
		FS05	Missile Barrier	FM05	Absorb Neutrons
		FS06	HELB Shielding	FM06	Spray
		FS07	Non-S/R Structural Support	FM07	Insulate
		FS08	Pipe Whip Restraint	FM08	Leakage Boundary (Spatial)
		FS09	Structural Pressure Boundary		
		FS10	Expansion/ Separation		
		FS11	Gaseous Release Path		
		FS12	Shutdown Cooling Water		
		FS13	Heat Sink		
		FS14	Pressure Relief		
		FS15	Structural Integrity (Attached)		
		FS16	Direct Flow		
		FS17	Shielding		

Attachment C: Walkdown Documentation Form

License Renewal Id No. <LRID>

<Plant System Name>

Walkdown Documentation Form

Plant Name: ______________________ **Unit Number:** _____

System/Structure Name: ______________________ **LR ID #:** ______________________

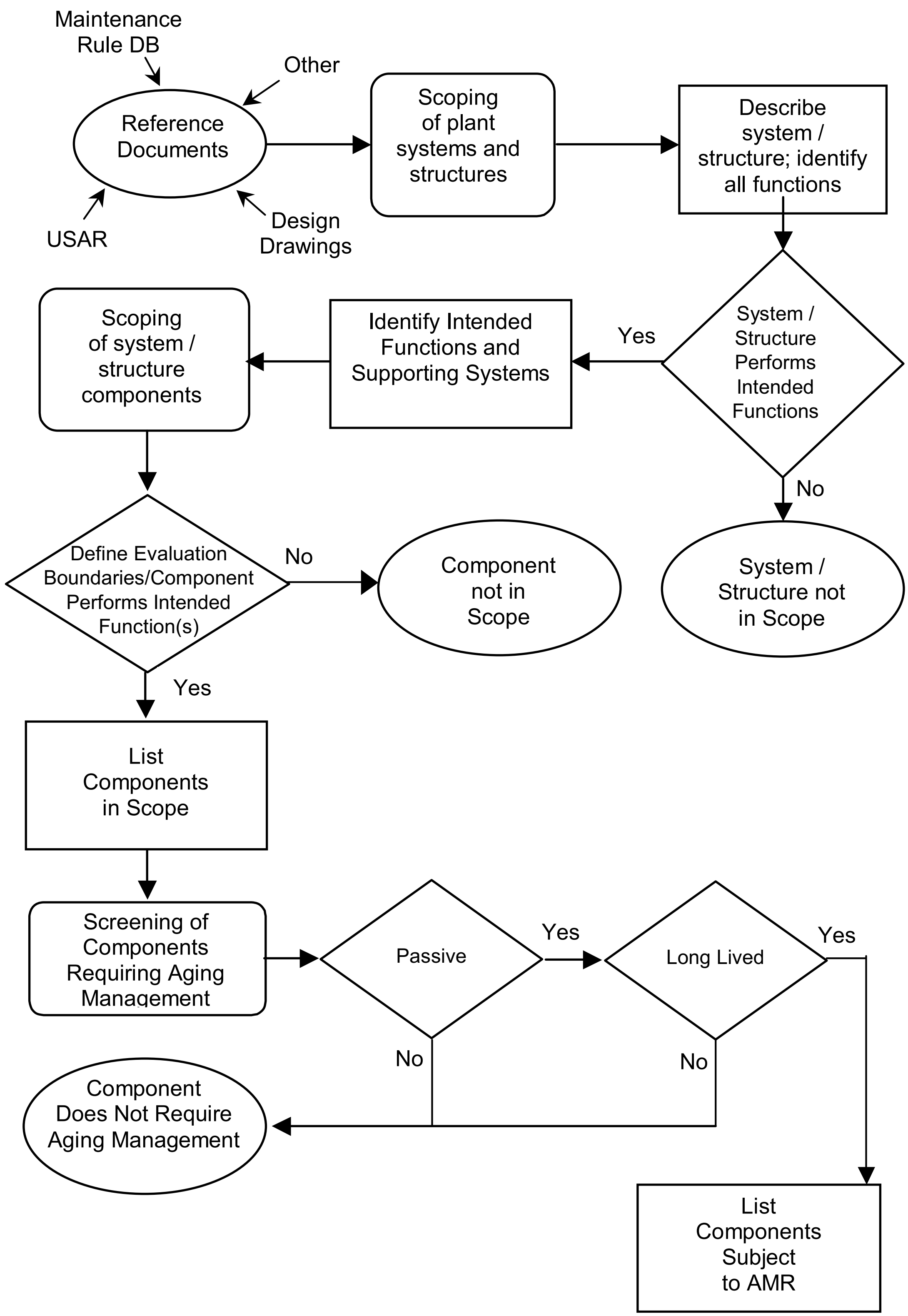
Walkdown Instructions:

Walkdown Findings:

Performed by: ______________________ Date:______________________

NOTE
This walkdown documentation form provides one acceptable way to document a walkdown. Other walkdown documentation acceptable to the Plant License Renewal Project Manager may be used.

Attachment D:
Scoping and Screening Process Flow



Attachment E:
Generic Structural and Mechanical Components

Generic Mechanical Components

Generic Component	Component Type (Note 1)	Comments
Closure Bolting	Closure Bolting	
High Strength Bolting	High Strength Bolting	Note 2
HVAC Ductwork	Ductwork	Note 4
Flexible Connectors (HVAC)	Flexible Connectors	Includes HVAC flexible boots
Flexible Hoses	Flexible Hoses	Note 3
Insulation	Insulation	
Neutron Absorbers (Boral)	Neutron Absorbers (Boral)	
Neutron Absorbers (Boraflex)	Neutron Absorbers (Boraflex)	
Piping	Pipe	Note 4
Spring Hangers – Sliding Surfaces	Spring Hangers – Sliding Surfaces	Note 5
ASME Class 1 supports	Supports – ASME 1	Note 5
ASME Class 2&3 supports	Supports – ASME 2&3	Note 5
ASME Class MC supports	Supports – ASME MC	Note 5
Mech. Equipment Supports – ASME Class 1	Supports – Mech Equip ASME 1	Note 5
Mech. Equipment Supports – ASME Class 2&3	Supports – Mech Equip ASME 2&3	Note 5
Mech. Equipment Supports – Non ASME	Supports – Mech Equip Non ASME	Note 5
HVAC duct supports	Supports – HVAC Duct	Note 5
Instrument supports & trays	Supports - Instrument	Note 5
Non ASME Supports	Supports – Non ASME	Note 5
Tubing	Tubing	Note 6

Notes:

1. Component type identified on the LRDMT selection list
2. Identify closure bolting in ASME Class component supports that is made of low alloy steel with a yield strength >150ksi.
3. Initially screen flexible hoses as a component not routinely replaced on a periodic basis. Maintenance activities that replace flexible hoses will be verified during AMR activities
4. Use only if a piping segment or HVAC duct segment number is not assigned. This component type includes piping, fittings, and nozzles.
5. Identify location (by structure).
6. The Tubing generic component includes the tubing, fittings, valves, and other components associated with the tubing portions highlighted on the license renewal boundary drawings.

Attachment E:
Generic Structural and Mechanical Components

Generic Structural Components

Generic Component	Component Type (Note 1)	Comments
Bellows	Bellows	
Blowout Panels	Blowout Panels	
Cable trays & supports	Cable trays and supports	
Caulking/sealants	Caulking/sealants	Not fire barrier seals
Compressible joints/seals	Compressible joints/seals	Pressure boundary - Not fire barrier seals
Concrete elements	Reinforced Concrete Beams, Columns, Walls, and Slabs	
Concrete block	Concrete block (masonry walls)	
Conduit and supports	Conduit and supports	
Dams/Dikes	Dams/Dikes	
Doors	Doors	See Note 2
Doors fire	Fire barrier doors	See Note 2
Duct banks	Duct banks, cable trench & manholes	
Electrical panels & enclosures	Electrical panels & enclosures	Includes electrical panels, racks, cabinets, and other enclosures
Fire barrier coatings/wraps	Fire barrier coatings/wraps	
Fire barrier seals	Fire barrier seals	
Hatches/plugs	Hatches/plugs	
Instrument panels & racks	Instrument panels & racks	Includes instrument racks, frames, panels, and enclosures
Instrument line supports/trays	Supports - instrument	Component type includes instrument trays
Liner – containment	Liner – containment	
Liner – spent fuel pool	Liner – spent fuel pool	
Liner – refueling	Liner – refueling	
Metal Siding	Metal Siding	

Generic Component	Component Type (Note 1)	Comments
Penetration	Penetration	
Penetration Boot Seals	Penetration Boot Seals	See Note 3
Penetrations mechanical	Penetrations mechanical	See Note 3
Penetrations electrical	Penetrations electrical	See Note 3
Piles	Piles	
Pipe whip restraints & jet shields	Pipe whip restraints & jet impingement shields	
Roofing Membrane	Roofing Membrane	
Spent Fuel Racks	Spent Fuel Racks	
Stairs/Platforms/Grates	Stairs/Platforms/Grates	
Structural Steel	Structural Steel	
Tunnel	Tunnel	
Waterstops	Waterstops	Note 4

Notes:
1. Component type identified on the LRDMT selection list
2. Flood doors with a fire barrier function should be evaluated as a fire barrier door with fire barrier and flood barrier functions.
3. Fire barrier seals, caulking and sealants are not included in the mechanical/electrical penetration component type. Fire barrier seals, caulking and sealants are evaluated as separate component types.
4. Verify CLB intended function

Attachment F:
Subcomponents, Consumables, and Short Lived Components

Category	Structure, Component, or Commodity Group	Considerations Applicable for This Category
Subcomponent	Packing, Gaskets, O-Rings and Component Seals	These subcomponents are not required to be called out explicitly during scoping and screening. They are implicitly addressed at the component level. These subcomponents are not credited with maintaining the integrity of the pressure boundary function of valve, pump and similar component housings.[1]
Subcomponent	Seals or caulking on structures or systems	These subcomponents are not required to be called out explicitly during scoping and screening. The structural aging management review will evaluate the use of these components.
Consumable	Oil, Grease, and Component Filters (oil or air)	These are short-lived consumables that are periodically replaced. As such, they are not subject to an aging management review.
Consumable	System Filters, Fire Extinguishers, Fire Hoses, and Air Packs	These are short-lived components that are replaced on condition.[2]
Component	Gas Bottles (cylinders)	These are short-lived components that are replaced on condition of low gas pressure.
Component	Radiation Detectors	These are active, short-lived components that are replaced on condition of low detector sensitivity.
Component	Control Rod Blades	These are short-lived component that are replaced as part of the Plant fuel management program.
Component	Fuel Assembly	These are short-lived components that are replaced as part of the Plant fuel management program.

1. Plant specifications implement the codes and standards applicable to piping and valves at the respective stations, including ASME Section III. Plant specifications identify the pressure boundary components of valves as the body of the valve, bonnet, body-bonnet connection, valve disc and related pressure retaining components. Packing, gaskets, O-rings and component seals are not credited with maintaining integrity of the pressure boundary function.

2. System filters are periodically replaced based on manufacturers' requirements. Fire extinguishers, fire hoses and air packs are periodically inspected and tested per the requirements of site-specific instructions that implement applicable National Fire Protection Association (NFPA) guidelines as documented in the Fire Hazards Analysis for each station.

Attachment G:
Passive Structure and Component Intended Functions

Function Code	Intended Function	Description
FM01	Pressure Boundary	Provide pressure-retaining boundary so that sufficient flow at adequate pressure is delivered, or provide fission product barrier for containment pressure boundary, or provide containment isolation for fission product retention
FM02	Throttle	Provide flow restriction
FM03	Filter	Provide filtration
FM04	Heat Transfer	Provide heat transfer
FM05	Absorb Neutrons	Absorb neutrons
FM06	Spray	Convert fluid into spray
FM07	Insulate	Control heat loss
FM08	Leakage Boundary (Spatial)	Non-safety-related component that maintains mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs
FS01	Structural Support	Provide structural and/or functional support to safety-related components
FS02	Fire Barrier	Provide rated fire barrier to confine or retard a fire from spreading to or from adjacent areas of the plant
FS03	Shelter, Protection	Provide shelter/protection to safety-related components
FS04	Flood Barrier	Provide flood protection barrier (internal and external flooding event)
FS05	Missile Barrier	Provide missile barrier (internally or externally generated)
FS06	HELB Shielding	Provide shielding against high energy line breaks
FS07	Non-S/R Structural Support	Provide structural support to non-safety-related components whose failure could prevent satisfactory accomplishment of required safety functions
FS08	Pipe Whip Restraint	Provide pipe whip restraint
FS09	Structural Pressure Boundary	Provide pressure boundary or essentially leak tight barrier to protect public health and safety in the event of any postulated design basis events

Function Code	Intended Function	Description
FS10	Expansion/ Separation	Provide for thermal expansion and/or seismic separation
FS11	Gaseous Release Path	Provide path for release of filtered and unfiltered gaseous discharge
FS12	Shutdown Cooling Water	Provide source of cooling water for plant shutdown
FS13	Heat Sink	Provide heat sink during SBO or design basis accidents
FS14	Pressure Relief	Provide over-pressure protection
FS15	Structural Integrity (Attached)	Non-safety-related component that maintains mechanical and structural integrity to provide structural support to attached safety-related piping and components
FS16	Direct Flow	Provide spray shield or curbs for directing flow
FS17	Shielding	Provide shielding against radiation
FE01	Electrical Continuity	Provide electrical connections to specified sections of an electrical circuit to deliver voltage, current or signals
FE02	Insulate (electrical)	Insulate and support an electrical conductor

Attachment H:
Internal and External Environments

NOTE
Internal and external environments to which components within the scope of license renewal are exposed are based on NUREG-1801 environments and are identified as "Evaluated" environments. See section 3.0 of reference 8, "Aging Effects Topical Report" for a list of evaluated environments to use for identification of internal and external environments. See reference 8 Attachment A for a description of each of the evaluated environments.

Diablo Canyon License Renewal Feasibility Study

TR-8DC
Aging Effects Topical Report

Revision 2
April 22, 2010

TR-8DC
Aging Effects Topical Report

Approval Page

Revision	Prepared by:	Checked By:	Approved by:	Owner Approved by:
0	Eric Blocher	Philippe Soenen	Eric Blocher	
Date	10/05/07	10/18/07	10/26/07	
1	Stan Shepherd Rye Davis	Dave Lipinski Philippe Soenen	David Kunsemiller	
Date	11/20/2009	12/17/2009	12/30/09	
2	Seemant Saxena	Ryan Gibbs	Scott Armando	Philippe Soenen
Date	4/22/2010	5/24/2010	5/25/10	5/25/2010

Revision Summary

Revision	Required Changes to Achieve Revision	Date
0	Initial Issue	10/26/07
1	Incorporated PCTF-007 which added applicable materials in Exhibit 4-1, clarified that Raw Water environment includes Submerged in Attachment B, clarified that Air – Outdoor environment includes salt-laden atmospheric air and salt water spray in Attachment B, revised temperature range for Atmosphere/Weather External in Attachment B per UFSAR Table	11/20/2009

	2.3-7, and clarified Submerged environment in Attachment B. Incorporated PCTF-012 which changed TR-8PV to TR-8DC on the cover page, and changed Wetted Gas to Plant Indoor Air (Internal) in Attachment A. Incorporated PCTF-025 which added a new Section 6.7 to cover Copper and Other Alloys potentially susceptible to Selective Leaching. Incorporated PCTF-026 which added a new Section 6.8 to cover Aluminized Steel. Incorporated PCTF-036 which deleted the Open Item on the Approval Page, and revised Section 9.6. Incorporated PCTF-027 which clarified that Air – Outdoor environment includes salt-laden atmospheric air and salt water spray in Attachment A. Incorporated PCTF-040 which revised Exhibit 4-1 to add Earthfill (rip-rap, stone, soil) for Atmosphere/Weather and Raw Water/Submerged, clarified Structural Environments in Attachment B, and revised the temperature range for Atmosphere/Weather External in Attachments A and C per UFSAR Table 2.3-7. Incorporated PCTF-059 which revised Reference 10.6, EPRI Mech Tools, from Rev. 3 to Rev. 4. Incorporated PCTFs DC050 and DC115 to align with the DCPP LRA.	
2	Added fiberglass under Attachment E as a new miscellaneous structural materials aging effect per PCTF-DC139	4/22/2010

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1.0 PURPOSE OF TOPICAL REPORT

The Aging Effects Topical Report provides the License Renewal Engineer with a standardized method for determining plant-specific and industry-identified aging effects and associated aging mechanisms for material and environment combinations. The aging effect topical report should be used as the primary reference when attempting to identify aging effects that are applicable for a given material-environment combination. References cited in this topical report should be reviewed as necessary to understand the aging effects and associated aging mechanisms.

The Aging Effect Topical Report will be revised during Aging Management Review activities to incorporate plant specific aging evaluation results, new industry operating experience, new industry precedents identified in NRC SERs, NUREG-1801 revisions, and applicable NRC Interim Staff Guidance documents.

2.0 INTRODUCTION

EPRI Mechanical Tools, EPRI Structural Tools, NUREG-1801, and published aging references were utilized to determine aging effects requiring management for mechanical and structural components at Diablo Canyon Power Plant (DCPP) facilities. Aging Effects information is consistent with NUREG-1801, Revision 1, dated September 2005, with exceptions identified in Section 7.0. The industry references were reviewed for applicability, tailored to address DCPP material and environments and to incorporate specific aging effects/mechanisms based upon plant experience.

The Aging Effect Topical Report identifies a reference for each aging mechanism and aging effect applicable to a given material and environment combination. References cited in this topical report should be reviewed as necessary to understand the aging effects and associated aging mechanisms. The aging effects are initially assumed valid until further evaluation concludes otherwise. Consistent with project technical instructions, the AMR engineer should evaluate the applicability of each aging effect and associated aging mechanism identified in the Aging Effect Topical Report for a given material/environment combination, and provide results in the project database.

The following are presented in this topical report:

Internal and External Environments
DCPP internal and external environments to which the components are exposed are identified in Section 3 with details provided in Attachment A for mechanical environments, Attachment B for structural environments, and Attachment C for electrical environments.

Materials Environment Combinations
Materials Environment combinations evaluated for DCPP mechanical and structural components within the scope of license renewal are identified in Section 4.

Aging Effects Requiring Management

Aging Effects requiring management for the identified DCPP material and environment combination are introduced in Section 5. Aging evaluation details including NUREG-1801 reference, industry references, and applicability details are presented in Attachment D for metallics and various non-metallics used in mechanical components; Attachment E for concrete and miscellaneous structural materials; and Attachment F for electrical materials.

Clarifications and Assumptions

Technical clarifications or assumptions associated with the aging evaluation process are presented in Section 6.

Exceptions to NUREG-1801 Aging Effects

The justifications for exceptions to the aging effect identified in NUREG-1801 are identified in Section 7. This section will be periodically updated to reflect plant specific considerations and current industry precedent.

Technical Evaluations of Select Operating Experience

Technical evaluations of select plant specific operating experience are presented in Section 8. This section includes additional details of phenomena documented in the plant operating experience and provides an aging management conclusion. This section will be updated to reflect plant specific considerations and current industry precedent as required. This section also includes industry operating experience identified since the September 2005 issue of NUREG-1801 Revision 1.

Further Evaluations of Concrete Aging Effects

Further evaluations required by NUREG-1801 for the following concrete aging effects are presented in Section 9:

- Loss of material (spalling, scaling) and cracking due to freeze-thaw
- Increase in porosity and permeability, loss of strength due to leaching of calcium hydroxide
- Expansion and cracking due to reaction with aggregates
- Cracking, loss of bond, loss of material (spalling, scaling) due to corrosion of embedded steel
- Increase in porosity and permeability, loss of material (spalling, scaling) due to aggressive chemical attack
- Cracks, distortion, increase in component stress due to settlement
- Reduction in foundation strength, cracking, differential settlement due to erosion of porous concrete subfoundation
- Reduction of strength and modulus due to elevated temperature
- Loss of material due to abrasion and cavitation

3.0 ENVIRONMENTS

Internal and external environments to which mechanical and structural components within the scope of license renewal are exposed have been identified as "Evaluated" environments and are listed below. "Evaluated" environments have been defined to identify environmental parameters or conditions that are applicable to several environments. To simplify the aging evaluation process, all NUREG-1801 environments for PWR components have been assigned to an "Evaluated" environment based on consistency with the specific environmental parameters or conditions of the "Evaluated" environment. Attachments A, B, and C provide a description for each of the evaluated environments noted below. Attachments A, B, and C also identify the assigned NUREG-1801 environments.

Evaluated Environments

- Internal Mechanical Environments
  - Borated Water Leakage
  - Closed Cycle Cooling Water
  - Demineralized Water
  - Diesel Exhaust
  - Dry Gas
  - Fuel Oil
  - Lubricating Oil
  - Plant Indoor Air
  - Potable Water (Environment not in NUREG-1801)
  - Raw Water
  - Reactor Coolant
  - Treated Borated Water
  - Secondary Water
  - Ventilation Atmosphere
  - Wetted Gas

- External Mechanical, Structural, and Electrical Environments
  - Adverse Localized Environment
  - Atmosphere/Weather
  - Borated Water Leakage
  - Buried
  - Closed Cooling Water
  - Dry Gas
  - Encased in Concrete
  - Fuel Oil
  - Lubricating Oil
  - Plant Indoor Air
  - Raw Water
  - Reactor Coolant
  - Secondary Water
  - Submerged
  - Treated Borated Water

- Ventilation Atmosphere (Mechanical Only)

Attachments A, B, and C identify the relationship of environments that were evaluated during mechanical, structural, and electrical reviews to the environments used in NUREG-1801. The following technical criteria or special considerations are associated with the NUREG-1801 environments. In addition, NUREG-1801 special conditions are identified with a bracketed designator in Attachments A and B.

Technical Criteria or Special Considerations
Associated With the NUREG-1801 Environments

- Temperature Threshold of 95°F for Thermal Stressors in Elastomers
- Temperature Threshold of 140°F for SCC in Stainless Steel
- Temperature Threshold of 482°F for Thermal Embrittlement in CASS
- Specification of limited applicability – components, aging effects, etc.

4.0 MATERIAL ENVIRONMENT GROUPS

Materials of construction and their associated environment for components within the scope of license renewal are identified by Exhibit 4-1. These material and environment groups are used to determine the applicable aging effects and associated aging mechanisms. The metallic material and environment groups that follow are applicable to multiple disciplines. Note the following:

- Specific metal alloys (e.g. A217 or 316) have not been identified, but have been considered in the applicable common material summary such as carbon steel or stainless steel. When applicable, specific metal alloy characteristics have been identified based on the aging mechanism.
- Because the minor differences in chemical content between different alloys in a group do not significantly affect the way in which the materials age; in many cases, detailed material specification was not necessary to identify aging effects or aging mechanisms.
- Treated water includes: closed cycle cooling water, demineralized water, reactor coolant, treated borated water, and secondary water.

Exhibit 4-1
AMR Groups – Material & Environments

	Aluminum	Carbon Steel, Low Alloy Steel & Cast Iron	Concrete	Copper Alloys	Neutron Absorbers	Nickel Alloys	Non-Metallic	Stainless Steel
Air/Indoor Air/ Ventilation Atmosphere/ Wetted Gas	X	X	X	X		X	X	X
Atmosphere/Weather	X	X	X	X			X	X
Borated Water Leakage	X	X				X		X
Buried (Soil)		X	X					X
Diesel Exhaust		X						X
Dry Air/Dry Gas		X		X			X	X
Encased in Concrete	X	X						X
Oil (Fuel and Lube)		X		X				X
Potable Water		X		X				
Raw Water / Submerged		X	X	X		X	X	X
Treated Water/Steam	X	X		X	X	X	X	X

5.0 AGING EFFECTS

Aging effects have been determined for specified material and environment combinations. Aging effects require management if they could cause loss of the component intended function during the extended period of operation.

EPRI Mechanical Tools, EPRI Structural Tools, NUREG-1801, and published aging references were utilized to determine aging effects requiring management for mechanical and structural material and environment groups. Attachment D identifies aging effects and associated aging mechanisms based on EPRI and NUREG-1801 references for various metallic and elastomer material-environment combinations. Attachment E identifies aging effects and associated aging mechanisms based on EPRI and NUREG-1801 references for various concrete material-environment combinations. The industry references were reviewed for applicability, tailored to address material and environments and, if applicable, to incorporate specific aging effects/mechanisms based upon plant experience.

6.0 CLARIFICATIONS AND ASSUMPTIONS

The following technical clarifications or assumptions associated with the aging evaluation process are identified:

6.1 Coatings and Linings

Some components contain internal and/or external coatings or linings that perform a protective function. Unless noted otherwise, these features are not credited for the elimination of aging effects requiring management.

6.2 Electrical Components

Aging management review of electrical cables and connectors is based on a spaces approach and is documented separately.

6.3 Carbon Dioxide Gas Environment

The DCPP license renewal project definition for “Dry Gas” (see Attachment A) incorporates the NUREG-1801, Ref. 1, Chapter IX, definitions for “Dried Air” and “Gas;” however, it takes exception to the NUREG-1801 definition of “Gas” that states it “is not meant to envelope gases in the fire suppression system.” The DCPP project evaluates Carbon Dioxide used in the fire suppression system as “Dry Gas” for the purposes of determining applicable aging effects when various materials are exposed to Caron Dioxide. The Carbon Dioxide used in the fire suppression system at DCPP procured as a commercial grade product with purity requirements to ensure high quality and prevent the intrusion of external contaminants (Reference TBD). When evaluating aging effects for the materials in the fire suppression system exposed to Carbon Dioxide it was concluded that due to the absence of moisture or wetting no aging effects were applicable. This position is consistent with the position taken in the Brunswick License Renewal Application (LRA) and the NRC staff review in the Brunswick License Renewal Safety Evaluation Report (SER).

From the Brunswick SER Section 3.3.2.3:

In RAI 3.3-4, the NRC staff stated that the applicant (Brunswick) did not identify aging effects for various materials exposed to a dry air/gas (internal) environment for various component commodities such as the Fire Protection System. The staff requested that the applicant provide the technical basis for not identifying loss of material as an aging effect for these components, including a discussion of the plant-specific operating experience related to components that are exposed to an air environment to support its conclusion.

In response, Brunswick provided the following discussion:

“Dry Gases - Examples of a dry gas environment include nitrogen, carbon dioxide and Halon-containing components in the Pneumatic Nitrogen System and the Fire Protection System. Experience has shown that commercial grade gases are provided as a high quality product with little if any external contaminants. Based upon nitrogen, carbon dioxide, and Halon environments not being subject to wetting, the BSEP methodology predicted no aging effects for these dry gases.”

The NRC staff reviewed Brunswick's response to RAI 3.3-4 and found that the response was "reasonable and acceptable" because the applicant clarified that "…(2) experience has shown that commercial grade gases are provided as a high quality product with little, if any, external contaminants..."

The Brunswick SER Section 3.3.2.3.12 repeatedly states that for various materials exposed to an environment of Carbon Dioxide, characterized as dry air/gas (internal), no aging effect is anticipated and no AMP is credited. To which the NRC concluded, "During its review of the information provided in the LRA, license renewal drawings, and licensing-basis information, the staff did not identify any omissions or discrepancies in the applicant's scoping and screening results for the components of the fire protection systems," thus, further endorsing the position that it's acceptable to evaluate Carbon Dioxide as a "Dry Air/Gas" environment.

6.4 Ventilation Atmosphere

Ventilation atmosphere is the environment to which the surface of components inside HVAC systems is exposed (e.g., heat exchanger tubes, etc.). Ventilation atmosphere is also defined as atmospheric/room/building air for ventilation systems with temperatures higher than the dew point, i.e. condensation can occur but only rarely, equipment surfaces are normally dry. Condensation on the surfaces of systems with temperatures below the dew point is considered raw water due to the potential for surface contamination.

6.5 Loss of Pre-Load

The discussion of bolt preload in EPRI NP-5769, Vol. 2, Section 10, indicates that job inspection torque is non-conservative since for a given fastener tension, more torque is required to restart the installed bolts. The techniques for measuring the amount of bolt tension in an assembled joint are both difficult and unreliable. Inspection of preload is usually unnecessary if the installation method has been carefully followed. Torque values provided in the procedures are based on criteria of stretch to cover the expected relaxation of the fasteners over the life of the joint. Gasket stress is also considered for pressure closure bolting.

6.6 High-Strength Bolting

High-strength bolting that is included in NSSS component supports (e.g., Steam Generator and Pressurizer supports) needs to be determined. Based on prior precedent, the Aging Effect Evaluation performed for Supports (LRID ZSUPP) should conclude that cracking due to SCC is an applicable aging effect for these components. The NUREG-1801 Bolting Integrity Program specifies appropriate lubricants and sealants to preclude introduction of significant contaminants and thus prevent the aging effect of cracking due to SCC.

6.7 Susceptibility to Selective Leaching for Copper Alloys and Other Alloys

NUREG-1801 Chapter IX and EPRI-1010639 EPRI Mechanical Tools, Revision 4, address Loss of Material due to selective leaching as an aging effect of interest with certain copper and iron alloys. Plant materials documentation generally details the alloy composition of a component, and the actual alloy composition is to be used with NUREG-1801. In some conditions, plant materials documentation simply specifies a word-name for an alloy (e.g. "brass" or "cast iron") without providing an ASTM or ASME alloy designation or composition detail. For the purposes of License Renewal, the following guidance will be employed in evaluating the aging of alloys identified only with word-names

6.7.1 Alloys That Are Susceptible to Selective Leaching

Brass – Copper alloys identified only as "brass" will be taken to be common yellow brass of composition Copper - 65%, Zinc - 35%. (Reference: McGraw Hill Engineering Manual, Third Edition)

Aluminum Bronze – Copper alloys identified only as "aluminum bronze" will be taken to be of composition Copper – 92%, Aluminum – 8%. (Reference: McGraw Hill Engineering Manual, Third Edition)

Grey Cast Iron – Alloys identified specifically as "grey cast iron" will be assumed to be susceptible to selective leaching.

6.7.2 Alloys That Are Not Susceptible to Selective Leaching

Naval Brass / Admiralty Brass – The nominal composition of Naval Brass is taken as Copper – 60%, Zinc – 39 ¼%, Tin – ¾% and of Admiralty Brass is taken as Copper – 71%, Zinc – 28%, Tin – 1% with Phosphorus, Arsenic or Antimony present. These copper alloys contain small amounts of tin, phosphorous, arsenic and/or antimony that have been identified as effectively inhibiting selective leaching. (Reference: McGraw Hill Engineering Manual, Third Edition, and EPRI-1010639 EPRI Mechanical Tools, Revision 4, App. A 3.1.2 and App. B 3.1.2)

Bronze – Copper alloys identified only as "bronze" will be assumed to be common commercial bronze of composition Copper – 90%, Zinc – 10%. (Reference: McGraw Hill Engineering Manual, Third Edition)

Phosphor Bronze – Copper alloys identified only as "phosphor bronze" will be assumed to be of composition Copper – 94 ¾ %, Tin – 5%, Phosphorus ¼ %. (Reference: McGraw Hill Engineering Manual, Third Edition).

Cast Iron – Alloys identified as "cast iron" will be assumed to be cast iron, and not "grey cast iron", unless explicitly specified.

6.8 Aluminized Steel

Aluminized steel is steel that has been hot-dip coated both sides with aluminum-silicon alloy. This process assures a tight metallurgical bond between the steel sheet and its aluminum coating, producing a material with a unique combination of properties possessed neither by steel nor by aluminum alone. Aluminized steel shows a better behavior against corrosion and keeps the properties of the base material steel for temperature lower than 800 °C. It is thus analogous to the NUREG-1801 definition of galvanized steel and will be considered as galvanized steel when used with NUREG-1801 for License Renewal purposes.

NOTE: Galvanized steel is conservatively treated as carbon steel for aging evaluation. This means that carbon steel aging management programs will be applied to carbon steel, zinc-galvanized steel and aluminized steel.

7.0 EXCEPTIONS TO NUREG-1801 AGING EFFECTS

Note
This section will be periodically updated to reflect plant specific considerations and current industry precedent.

7.1 Thermal Aging Embrittlement of CASS

There is cast austenitic stainless steel (CASS) in the DCPP Primary loop piping. For pump casings and valve bodies, based on the assessment documented in the letter dated May 19, 2000 from NRC to NEI (Christopher I. Grimes , U. S. NRC, License Renewal and Standardization Branch, to Douglas J. Walters, NEI, License Renewal Issue No. 98-0030, Thermal Embrittlement of Cast Stainless Steel Components, May 19,2000), screening for the susceptibility to thermal aging is not required.

7.2 Thermal Aging of Elastomers (HVAC Elastomers)

Hardening and loss of strength of elastomers can be induced by thermal aging, exposure to ozone, oxidation, and radiation. In general, if the ambient temperature is less than about 95°F (35°C), then thermal aging may be considered not significant for rubber, butyl rubber, neoprene, nitrile rubber, silicone elastomer, fluoroelastomer, EPR, and EPDM. When applied to the elastomers used in electrical cable insulation, it should be noted that most cable insulation is manufactured as either 75°C (167°F) or 90°C (194°F) rated material. (NUREG-1801, Rev. 1, Chapter IX, Section D)

HVAC Elastomers:

The ambient temperatures for in-scope HVAC components are expected to be above 95°F. Therefore, thermal aging may be considered significant for in-scope duct flexible connectors (NUREG-1801, Rev. 1, Chapter IX, Section D).

7.3 Wear of HVAC Flexible Duct Connections

Loss of material due to wear is a result of relative motion between components. Elastomers in mechanical systems (e.g., joint seals and flexible connections) may experience wear as a result of their flexible nature and the small vibrations and/or movement of rotating components (e.g., fans). As such, loss of material due to wear of elastomers materials may be a concern. However, this concern is dependent on the specific elastomer (for which abrasion resistances vary) and condition, and thus requires plant-specific consideration.

DCPP HVAC systems that have in-scope flexible connectors used between fans and ductwork will require evaluation. The evaluation should identify those flex connectors that are essentially rigid and are not expected to rub against other components enough to result in mechanical wear. Therefore, no AMP would be necessary to manage loss of material due to wear for the components.

7.4 Aging of Boraflex in Fuel Racks

Boraflex is used at Diablo Canyon. Boraflex panels are not within the scope of license renewal. Boraflex panels are not required for criticality control in the spent fuel pools and do not perform an intended function. Therefore aging management is not required (reference DCPP License Amendment 154 dated September 20, 2002 and Technical Specification Bases B3.7.16).

7.5 Aging of Electrical Transmission Conductors

Industry experience has shown that transmission conductors are designed and installed not to swing significantly and cause wear due to wind induced abrasion and fatigue. Therefore, loss of material due to wind induced abrasion and fatigue is not an applicable aging effect requiring management for the period of extended operations.

The most prevalent mechanism contributing to loss of conductor strength of an Aluminum Conductor Steel Reinforced (ACSR) transmission conductor is corrosion, which includes corrosion of the steel core and aluminum strand pitting. ACSR conductors, degradation begins as a loss of zinc from the galvanized steel core wires. Corrosion rates depend largely on air quality, which involves suspended particles in the air, SO2 concentration, rain, fog chemistry, and other weather conditions. The DCPP outdoor environment is not subject to industry air pollution that would cause significant corrosion of the transmission conductors. The DCPP outdoor environment is subject to saline conditions and will require further evaluation.

The National Electrical Safety Code (NESC) requires that tension on installed conductors be a maximum of 60% of the ultimate conductor strength. The NESC also sets the maximum tension a conductor must be designed to withstand under heavy load requirements, which includes consideration of ice, wind, and temperature.

The DCPP outdoor environment is not subject to industry air pollution. The DCPP outdoor environment is subject to saline conditions. Aluminum bus material, galvanized steel support hardware, and stainless steel connection material will require evaluation to determine any appreciable aging effects in this environment.

DCPP ACSR transmission conductor information will be determined during the aging evaluation process and compared to prior precedents such as the Ontario Hydroelectric study of ACSR transmission conductors.

7.6 Aging of Electrical Connections

Thermal Cycling, Ohmic Heating and Electrical Transients

The only metallic parts of DCPP electrical cable connections that could potentially be exposed to thermal cycling and ohmic heating are those that carry significant current in power supply circuits. At DCPP, power supply cables are installed in a continuous run from the supply, e.g., switchgear, to the load, e.g., motor. The metallic parts of the connections to the supply and load are part of, or internal to, active components, e.g., the switchgear and motor, and therefore any aging is managed as part of the active components and not subject to aging management review. Mechanical stress associated with electrical faults is not a credible aging mechanism because of the low frequency of occurrence for such faults and the use of circuit production devices. Stresses due to forces associated with electrical faults and transients are mitigated by the fast action of circuit protective devices at high currents. Therefore, this stressor is not applicable.

Vibration

The only metallic parts of electrical cable connections exposed to vibration are those that are a part of, or internal to, active components that either cause vibration, such as motors, or are attached to mechanical systems that transmit vibration, such as valve operators or panels. Because they are parts of active components, any aging is managed as part of the active components and not subject to aging management review.

Chemical Contamination

The metallic parts of electrical cable connections are protected from contamination by their location inside active components or terminal boxes. At DCPP, corrosive chemicals are not stored in most areas of the plant. Routine releases of corrosive chemicals to areas inside plant buildings do not occur during plant operation. Such a release, and its effects, would be an event, not an effect of aging requiring management. Therefore, this stressor is not applicable.

Oxidation and Corrosion

Oxidation and corrosion occur most frequently in the presence of moisture and contamination such as industrial pollutants or salt deposits. The metallic parts of DCPP electrical connections are protected from moisture by several barriers. The first barrier is the active component in which the connections are mounted. The second barrier is the building in which the equipment is located. The vast majority of metallic parts of electrical connections are located inside active components that are, in turn, located in a structure with a controlled environment. Splices are protected by tape, heat shrink covering, or enclosed in an engineered splice kit. Metallic parts of electrical connections are typically made of copper or copper alloy plated with a corrosion resistant coating material to protect the base metal from oxidation and provide for low electrical resistance. Because they are protected as described above, the metallic parts of electrical connections experience no appreciable change in operating conditions, and are not exposed to an industrial or oceanic environment. Therefore, this stressor is not applicable.

7.7 Aging of Electrical Insulators

There are two basic types of insulators: station post insulators and strain (or suspension) insulators. Station post insulators are large and rigid. They are used to support stationary equipment such as switchyard bus and disconnect switches. Strain insulators are used in applications where movement of the supported conductor is expected and allowed. This includes maintaining tensional support of transmission conductors between transmission towers or other supporting structures.

The insulating material is typically porcelain, which is a hard, white or grey non-porous ceramic made of kaolin, feldspar, and quartz or flint. All of the exposed porcelain parts are then covered with an oven-baked glaze. Cement is then used as filler for mechanically joining the porcelain with the metal caps and pins. Typically, a high quality Portland cement is used.

DCPP is located in an area with nominal rainfall and where the outdoor environment is not subject to industry air pollution. Contamination buildup on the high-voltage insulators is not a problem due to rainfall periodically washing the insulators. Degradation of insulator quality in the absence of surface contamination is not an aging effect requiring management. The DCPP outdoor environment is subject to saline conditions and will require further evaluation.

Industry experience has shown that transmission conductors are designed and installed not to swing significantly and cause wear, due to wind induced abrasion and fatigue. The DCPP transmission conductors are designed and installed not to swing significantly and cause wear due to wind induced abrasion and fatigue. Therefore, loss of material due to wind induced abrasion and fatigue is not an applicable aging effect requiring management.

8.0 TECHNICAL EVALUATION OF SELECT OPERATING EXPERIENCE

Note
This section will be periodically updated to reflect plant specific considerations.

No plant specific considerations evaluated.

9.0 FURTHER EVALUATION OF CONCRETE AGING EFFECTS

Note
The following further evaluations are presented as a starting point to perform aging evaluation of concrete elements. Further evaluations will be developed based upon plant specific concrete mix, existence of aggressive environments, temperature/weather considerations, and plant specific configuration details.

Further evaluations of concrete aging effects are applicable to NUREG-1801 (Ref. 10.3) Groups 1, and 3 through 8 structures. Further evaluations were developed based upon plant specific concrete mix, existence of aggressive environments, temperature/weather considerations, operating experience and plant specific configuration details. Incorporated into these evaluations are technical details of the aging management issues presented in the following sections of NUREG-1800 (Ref. 10.4):

- Section 3.5.2.2.1.1 (Aging of Inaccessible Concrete Areas),
- Section 3.5.2.2.1.2 (Cracks and Distortion due to Increased Stress Levels from Settlement; Reduction of Foundation Strength due to Erosion of porous Concrete Sub-Foundations, if Not Covered by Structures Monitoring Program),
- Section 3.5.2.2.1.3 (Reduction of Strength and Modulus of Concrete Structures due to Elevated Temperature),
- Section 3.5.2.2.1.8 (Scaling, Cracking, and Spalling due to Freeze-Thaw; and Expansion and Cracking due to Reaction with Aggregate), and
- Section 3.5.2.2.2.1 (Aging of Structures Not Covered by Structures Monitoring Program).

9.1 Loss of material (spalling, scaling) and cracking due to freeze-thaw

Repeated cycles of freezing and thawing may alter both the mechanical properties and physical form of concrete that is susceptible to such action, thus causing cracking of the concrete. The freeze-thaw phenomenon occurs when water freezes within the concrete's pores, creating hydraulic pressure from the expansion of the freezing water. This pressure either increases the size of the cavity or forces water out of the cavity into surrounding voids. The resistance of absorptive coarse aggregates to freeze-thaw damage depends primarily on the absorption characteristics (volume of fine pores) of the aggregate, the presence of moisture to saturate the aggregate, and the permeability of the hardened cement mortar matrix to the passage of water. For damage to occur by freezing of absorptive coarse aggregates, the aggregate must be saturated. Saturation may occur when water is available from an outside source. Freeze-thaw damage typically occurs on relatively flat concrete surfaces such as pavement, where water remains in contact with the concrete. Freeze-thaw damage is characterized by scaling, cracking, and spalling. It starts at the surface and is readily detected by surface inspections. Freeze-thaw damage, if present, is expected to be a local condition and by itself will not affect the strength of the concrete.

Freeze-thaw damage is not significant for reinforced concrete in foundations, and in above and below grade exterior concrete, for plants located in areas in which weathering conditions are considered severe (weathering index >500 day-inch/yr) or moderate (100-500 day-inch/yr), provided that the concrete mix design meets the air content (entrained air 3-6%) in accordance with ASTM C-260 (reference 10.23) and water-to-cement ratio (0.35-0.45) specified in ACI 318-71 (reference 10.21) or ACI 349-85 (reference 10.22).

9.2 Increase in porosity and permeability, loss of strength due to <u>leaching of calcium hydroxide</u>

The loss of certain salts, including calcium hydroxide, from the concrete matrix by exposure to flowing or penetrating water, can reduce the strength of concrete. Leaching typically is a concern associated only with low-density or porous concrete.

Seismic Category I concrete components in the nuclear plant utilize high-density, low-permeability concrete. Crack control is achieved through proper design, detailing, and installation of reinforcement in accordance with ACI 318-71 (reference 10.21) or later edition and other applicable standards. Therefore, leaching is not an aging mechanism requiring management for Seismic Category I concrete components.

9.3 Expansion and cracking due to <u>reaction with aggregates</u>

Certain mineral constituents of aggregates react with chemical compounds that compose the portland cement, most notably alkalis. Alkalis may also be introduced from improper admixtures, salt-contaminated aggregates, seawater or deicing salt. However, it is only when the expansive reaction products become extensive and cause cracking of concrete that aggregate reactivity is considered a deleterious reaction. Three principal deleterious reactions between aggregates and alkalis have been identified as alkali-aggregate, cement-aggregate, and expansive alkali-carbonate reactions.

Highly siliceous aggregate materials in Kansas, Nebraska, and Wyoming areas have produced concrete deterioration (map cracking) due to reaction with alkalies in cement. This type of distress should not be a problem for nuclear plant concrete components, because the problem is regional, and it can be controlled by replacing 30% of the materials with crushed limestone aggregates. Certain dolomitic limestone aggregates containing some clay react with alkalies to produce expansive reactions. This problem can be identified and controlled by diluting the reactive aggregate with a less susceptible material and using low-alkali-content cement. If the aggregate was tested and found to be potentially reactive, but the provisions of ACI 201.2R-77 (reference 10.29) or equivalent were adhered to, then generally the effects of reactions with aggregates will not be significant.

Industry operating history does not indicate that structural integrity is significantly affected by alkali-aggregate reactions. Non-reactive aggregates were used at nuclear power plants within the United States. Aggregates were selected to conform to ASTM C33-74 (reference 10.20) and subjected to petrographic testing in accordance with ASTM C 295 (reference

10.26) to show that the aggregate is non-reactive. Therefore, reaction with aggregates is not an applicable aging mechanism.

9.4 Cracking, loss of bond, loss of material (spalling, scaling) due to corrosion of embedded steel

The aging effects due to corrosion of embedded steel and steel reinforcement (rebar) are visible concrete degradation and steel corrosion. The presence of corrosion products on embedded steel subjects the concrete to tensile stress that eventually causes hairline cracking, rust staining, spalling, and more cracking. These actions will expose more embedded steel and steel reinforcement to a potentially corrosive environment and cause further deterioration in the concrete. A loss of bond between the concrete and embedded steel/steel reinforcement will eventually occur, along with a reduction in steel cross-section which can ultimately impair structural integrity.

The high alkalinity (pH > 12.5) of concrete provides an environment around embedded steel and steel reinforcement which protects them from corrosion. If the pH is lowered (e.g., to 10 or less), corrosion may occur. However, the corrosion rate is still insignificant until a pH of 4.0 is reached. The severity of corrosion is influenced by the properties and type of cement and aggregates as well as the concrete moisture content.

Since good design and construction practices are sufficient to preclude embedded steel and steel reinforcement corrosion in the absence of other aging mechanisms, corrosion of embedded steel and steel reinforcement would not be an applicable aging mechanism for nuclear power plant concrete structures and structural members so designed and constructed.

9.5 Increase in porosity and permeability, loss of material (spalling, scaling) due to aggressive chemical attack

Concrete, being highly alkaline (pH > 12.5), is vulnerable to degradation by strong acids. Acid attack may increase porosity and permeability of concrete, reduce its alkaline nature at the surface of the attack, reduce strength, and render the concrete subject to further deterioration. Below grade, sulfate solutions of sodium, potassium, and magnesium sometimes found in groundwater may attack concrete, often in combination with chlorides. Continued or frequent cyclic exposure to acidic solutions with pH < 5.5, Chloride solutions >500 ppm , or Sulfate solutions >1500 ppm is necessary for aggressive chemicals to cause significant concrete degradation.

If the concentrations of acid and aggressive chemicals are all below the threshold limits, aggressive chemicals are not an applicable aging mechanism for concrete structures and structural members at those power plant sites.

Since aggressive chemicals are contained at the plant sites, system leakage is possible that could cause the concrete to be exposed to chemicals beyond required limits. However, leaks are not expected to continue for the extensive periods required for degradation, and repairs would be completed prior to loss of intended function.

9.6 Cracks, distortion, increase in component stress due to settlement

The DCPP Seismic Category I structures and non-Seismic Category I structures housing Design Class I equipment are founded on bedrock. (Ref. DCPP FSAR Section 2.5.1.2.6.5) The Design Class I tanks are supported on concrete fill down to bedrock and are anchored to bed rock with rock anchors. (Reference: FSAR Section 3.8.3.1 and DCM T-28, Section 4.3.) A small local zone beneath a portion of buried ASW piping is susceptible to liquefaction. The associated liquefaction-induced settlements were considered in the design of the buried ASW piping. (Reference: DCPP FSAR Section 2.5.4.8).

9.7 Reduction in foundation strength, cracking, differential settlement due to erosion of porous concrete subfoundation

Diablo Canyon does not have porous concrete subfoundations.

9.8 Reduction of strength and modulus due to elevated temperature

Long-term exposure to elevated temperatures in excess of 300°F may cause surface scaling and cracking of concrete. Elevated temperatures may cause changes in the material properties of concrete. The compressive strength, tensile strength, and modulus of elasticity are reduced when exposed to temperatures exceeding 150°F (general) area or 200°F (localized) for prolonged periods.

Exposure to extremely high levels of fast and slow neutrons may cause aggregate growth, decomposition of water, or thermal warming of concrete. Extremely high gamma radiation affects the cement paste portion of the concrete, producing heat and causing water migration. As the temperature of concrete increases and free water within the concrete evaporates, the structural characteristics of concrete may be degraded. With water loss, concrete may experience a decrease in its compressive, tensile, and bonding strengths, and as well as its modulus of elasticity. Degradation owing to irradiation is not always observable, but may be evidenced as cracking owing to thermal stress.

9.9 Loss of material due to abrasion and cavitation

Water moving on concrete surfaces may carry abrasive materials or create a negative pressure (vacuum) that leads to abrasion or cavitation of the surface of the concrete. If significant amounts of concrete are removed by either of these processes, pitting or aggregate exposure occurs.

Abrasion or cavitation may cause a loss of material in concrete structures and structural members that are continuously exposed to flowing water containing abrasives. The water velocity and amount of abrasives present must be individually evaluated to determine the potential for significant degradation. Cavitation damage is not common at water velocities of less than 40 fps for open channel flow and less than 25 fps for closed conduit flow, and it is expected that most uses of concrete in the nuclear power plants in the scope of license renewal are not exposed to excessive velocities of water containing abrasives.

10.0 REFERENCES

10.1 NEI 95-10, Revision 6, Industry Guideline for Implementing the Requirements of 10CFR54 – The License Renewal Rule

10.2 Title 10, United States Code of Federal Regulations, Energy," Part 54 (10 CFR 54). "Requirements for Renewal of Operating Licenses for Nuclear Power Plants"

10.3 NUREG-1801, Generic Aging Lessons Learned (GALL) Report, Revision 1, September 2005

10.4 NUREG-1800, Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants, Revision 1, September 2005

10.5 EPRI 1002950, Aging Effects for Structures and Structural Components, Revision 1, Final Report, July 2003, Electric Power Research Institute.

10.6 EPRI 1003056, Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Revision 3, Electric Power Research Institute.

10.7 Technical Report SANDIA96-0344, Aging Management Guideline for Commercial Nuclear Power Plants Electrical Cables and Terminals, September 1996.

10.8 Fontana and Greene, Corrosion Engineering, 1978.

10.9 Engineered Materials Handbook, Volume 1, Composites, American Society of Metals Handbook Committee.

10.10 Engineered Materials Handbook, Volume 2, Engineering Plastics, American Society of Metals Handbook Committee.

10.11 EPRI 1003057, License Renewal Electrical Handbook, December 2001. Electric Power Research Institute.

10.12 TR-104748S, Boric Acid Corrosion Guidebook, April 1995, Electric Power Research Institute.

10.13 WCAP-14422, License Renewal Evaluation: Aging Management for Reactor Coolant System Supports, Revision 2-A, December 2000, Westinghouse Owners Group Life Cycle Management/License Renewal Program and Electric Power Research Institute.

10.14 WCAP-14574-A, License Renewal Evaluation: Aging Management for Pressurizers, December 2000, Westinghouse Owners Group Life Cycle Management/License Renewal Program.

10.15 WCAP-14575-A, Aging Management Evaluation for Class 1 Piping and Associated Pressure Boundary Components, December 2000, Westinghouse Owners Group Life Cycle Management/License Renewal Program.

10.16 WCAP-14577, License Renewal Evaluation: Aging Management for Reactor Internals, Revision 1-A, March 2001, Westinghouse Owners Group Life Cycle Management/License Renewal Program.

10.17 WCAP-14581, Aging Management Evaluation for Reactor Pressure Vessel, Revision 1, October 2001, Westinghouse Owners Group Life Cycle Management/License Renewal Program.

10.18 WCAP-14757, Aging Management Evaluation for Steam Generators, May 1997, Westinghouse Owners Group Life Cycle Management/License Renewal Program.

10.19 CE NPSD-1216, Generic Aging Management Review Report for the Reactor Vessel Internals, Revision 0, March 2001

10.20 ASTM C33-74, Standard Specification for Concrete Aggregates

10.21 ACI 318-71, Building Code Requirements for Reinforced Concrete

10.22 ACI 349-85, Code Requirements for Nuclear Safety Related Concrete Structures
10.23 ASTM C260-74, Specification for Air Entraining Admixtures for Concrete
10.24 ASTM C94-74, Specification for Ready-Mixed Concrete
10.25 ASTM C150-74, Specification for Portland Cement
10.26 ASTM C295-65, Standard Practice for Petrographic Examination of Aggregates for Concrete
10.27 ASTM C131-69, Standard Test Method for Resistance to Degradation of Small-Size Coarse Aggregate by Abrasion and Impact in the Los Angeles Machine
10.28 ACI 301-72, Specifications for Structural Concrete for Buildings
10.29 ACI 201.2R-77, Guide to Durable Concrete
10.30 McGraw Hill Engineering Manual, Third Edition
10.31 DCPP UFSAR, Rev. 18
10.32 DCM T-28, Design Class 1 – Outdoor Water Storage tanks, Rev. 1
10.33 PG&E Letter LRFS-10-007

Attachment A
Evaluated Mechanical Environments

Mechanical Environments		
Evaluated Environment	**NUREG-1801 Environment**	**Description**
Internal		
Demineralized Water	Treated Water	Demineralized water or chemically purified water which is the source for water in all clean systems such as the primary or secondary coolant systems. Demineralized water is monitored for quality under the Water Chemistry Aging Management Program and depending on the system, demineralized water may require additional processing.
Treated Borated Water	Treated Borated Water	Treated water with boric acid that is monitored for quality under the Water Chemistry Aging Management Program.
	Treated Borated Water >60 º C (140 º F) [SCC Threshold for Stainless Steel]	
	Treated Borated Water >250 º C (482 º F) [Thermal Embrittlement Threshold for CASS in ECCS Systems]	
Reactor Coolant	Reactor Coolant	Water in reactor coolant systems at or near full operating temperature that is treated and monitored for quality under the Primary Water Chemistry Aging Management Program.
	Reactor Coolant >250C (>482F) [Thermal Embrittlement Threshold for CASS]	
	Reactor Coolant and Neutron Flux [Neutron Irradiation Embrittlement]	
	Reactor Coolant >250C (>482F) and Neutron Flux [Thermal Embrittlement Threshold for CASS and Neutron Irradiation Embrittlement]	
	Reactor Coolant and Secondary Feedwater/Steam [TLAA IV.D1-21]	
	Reactor Coolant/Steam [RCS Piping IV.C2-13 and Pressurizer IV. C2-24]	
Secondary Water		Steam generator secondary systems water (including condensate, feedwater and steam) that is treated and monitored for quality under the Secondary Water Chemistry Aging Management Program and controlled for protection of steam generators.
	Treated Water	
	Treated Water >60 º C (140 º F) [SCC Threshold for Stainless Steel]	
	Secondary Feedwater/Steam	
	Secondary Feedwater	
Steam	Steam	Secondary water that has been converted to steam or heating and process steam produced from the auxiliary boiler
	Secondary Feedwater/Steam	
Closed Cycle Cooling Water	Closed Cycle Cooling Water	Water for component cooling that is treated and monitored for quality under the Closed-Cycle Cooling Water System Aging Management Program.
	Closed Cycle Cooling Water >60 º C (140 º F) [SCC Threshold for Stainless Steel]	
	Treated Water	

Mechanical Environments		
Evaluated Environment	**NUREG-1801 Environment**	**Description**
Raw Water	Raw Water	Water from the circulating water system or ultimate heat sink for use in open-cycle cooling systems. Floor drains and building sumps may be exposed to a variety of untreated water that is classified as raw water for the determination of aging effects. Raw water may contain contaminants, including oil and boric acid, as well as originally treated water that is not monitored by a chemistry program.
Lubricating Oil	Lubricating Oil	Lubricating oils are low-to-medium viscosity hydrocarbons, with the possibility of containing contaminants and/or moisture, used for bearing, gear, and engine lubrication. Lube oil is monitored for the possibility of water by the Lube Oil Analysis Aging Management Program.
Fuel Oil	Fuel Oil	Diesel fuel oil or liquid hydrocarbons used to fuel diesel engines. Fuel oil is monitored for the possibility of water and microbiological organisms by the Fuel Oil Chemistry Aging Management Program.
Dry Gas	Dried Air [Common Miscellaneous Material/Environments]	Internal gas environments from dry air (conditioned to reduce the dew point well below the system operating temperature), inert or non-reactive gases. Includes compressed instrument air, nitrogen, oxygen, hydrogen, helium, Halon CO2, or Freon.
	Gas [Common Miscellaneous Material/Environments]	
Diesel Exhaust	Diesel Exhaust[VII H2-1 & H2-2]	Gases, fluids, particles present in diesel engine exhaust.
Ventilation Atmosphere	Air – Indoor Uncontrolled	Atmospheric/room/building air for ventilation systems with temperatures higher than the dew point. Condensation can occur but only rarely, equipment surfaces are normally dry. • Ventilation atmosphere is evaluated with the NUREG-1801 environment of condensation when the air contains significant amounts of moisture (enough to cause loss of material) and the internal surface or external surface have temperatures below the dew point. • Ventilation atmosphere is evaluated with the NUREG-1801 environment of condensation when used for the drains associated with the internal or external surfaces exposed to condensation. • Ventilation atmosphere environments evaluated with condensation are considered to be potentially aggressive when surface contaminants are present. Also the environment to which the external surface of components inside HVAC systems is exposed.
	Condensation (Internal)	
	Air – Indoor Uncontrolled (Internal/External)	
	Air – Indoor Controlled (external)	

Mechanical Environments		
Evaluated Environment	**NUREG-1801 Environment**	**Description**
Plant Indoor Air	Condensation (Internal)	Indoor air or non-dried compressed gas with temperatures higher than the dew point. Condensation can occur, but only rarely; equipment surfaces are normally dry. Plant indoor air (internal) or non-dried compressed gas is evaluated with the NUREG-1801 environment of condensation when the air contains significant amount s of moisture (enough to cause loss of material) and the internal surface has temperatures below the dew point. Plant Indoor Air is evaluated with the NUREG-1801 environment of condensation when used for the drains associated with the internal surfaces exposed to condensation. Plant indoor air environments evaluated with condensation or moist air are considered to be potentially aggressive when surface contaminants are present.
	Air [Glass Piping Elements VII.J-7 and VIII.I-4]	
	Moist Air or Condensation [Diesel Piping Components VII.H2-21]	
Potable Water	This Environment is Not in NUREG-1801	Water treated for drinking or other personnel uses.
Sodium Hydroxide	This Environment is not in NUREG-1801	Treated water with elevated pH due to the presence of NaOH or LiOH. Sodium hydroxide and Lithium Hydroxide are used in the regeneration process for demineralizer resins, and as a water treatment chemical to achieve and maintain an elevated pH in some treated water applications.
External		
Plant Indoor Air	Air – Indoor Uncontrolled (External)	Indoor air with temperatures higher than the dew point. Condensation can occur, but only rarely; equipment surfaces are normally dry. Plant indoor air is evaluated with the NUREG-1801 environment of condensation when the air contains significant amounts of moisture (enough to cause loss of material) and the external surface has temperatures below the dew point. Plant indoor air is evaluated with the NUREG-1801 environment of condensation when used for the drains associated with the external surfaces exposed to condensation. Plant indoor air environments evaluated with condensation or moist air are considered to be potentially aggressive when surface contaminants are present.
	Air – Indoor Uncontrolled (Internal/External)	
	Air Indoor	
	Air – Indoor Controlled (External) [VII.J-1 and VIII.I-13]	
	Air With Leaking Secondary Side Water and/or Steam [Steam Generator (Once Through) – IV.D2-5]	
	Air With Steam or Water Leakage [Closure Bolting]	
	Condensation (External)	
Borated Water Leakage	Air With Reactor Coolant Leakage.	The borated water leakage environment applies in plant indoor and outdoor areas that include components and systems that contain borated water and that could leak on nearby components or structures.
	Air With Borated Water Leakage.	
	Air With Reactor Coolant Leakage (Internal) (RPV Leak Detection Line IV.A2-5)	
	Air With Metal Temperature up to 288C (550F) [Pressurizer Integral Support - IV.C2-16]	

Mechanical Environments		
Evaluated Environment	**NUREG-1801 Environment**	**Description**
	System Temperature up to 340C (644F) [Steam Generator Closure Bolting and TLAA]	
Atmosphere /weather	Air – Outdoor Air – Outdoor (External) (includes salt-laden atmospheric air and salt water spray) Air – Indoor and Outdoor	The atmosphere/weather environment consists of moist, ambient temperatures, humidity, and exposure to weather, including precipitation and wind. The component is exposed to air and local weather conditions. Temperature extremes range from 24°F to 104°F.
Buried	Soil	Components/equipment that are buried in soil. Soil is a mixture of inorganic materials produced by the weathering of rocks and clays, and organic material produced by decomposition of vegetation. Voids containing air and moisture occupy about 50% of the soil volume. Properties of soil that can affect aging include water content, pH, ion exchange capacity, density, and permeability. External environment for components exposed to soil (including air/soil interface) or buried in the soil, including groundwater in the soil. The ground water has been determined to be non-aggressive.
Submerged (Note: Use Appropriate Internal Environment)	Use Appropriate Internal Environment	Components/equipment that are completely or partially submerged in: • Water (operating or process fluid) • Oil/fluids (lube, fuel, EHC, etc.) The environment for submerged components will be identified using one of the internal environments previously identified.
Encased in Concrete	Concrete	Piping or components that are encased in concrete.

Attachment B
Evaluated Structural Environments

Structural Environments		
Evaluated Environment	**NUREG-1801 Environment**	**Description**
Plant Indoor Air (Structural)	Any [Reaction With Aggregates]	Structures are subject to the same conditions covered in Plant Indoor Air External Mechanical Environment. Indoor air on structures with temperatures higher than the dew point, i.e., condensation can occur but only rarely, structural surfaces are normally dry. Condensation on the surfaces of structures with temperatures below the dew point is considered raw water due to the potential for surface contamination.
	Air - Indoor Uncontrolled	
	Soil [Cracks and Distortion Due to Increased Stress Levels From Settlement]	
	Various [Elastomers III A6-12]	
Atmosphere/ Weather (Structural)	Any [Reaction With Aggregates]	Structures are subject to the same conditions covered in Atmosphere/Weather External Mechanical Environment. The atmosphere/weather environment consists of moist, ambient temperatures, humidity, and exposure to weather, including precipitation and wind. The component is exposed to air and local weather conditions. Temperature extremes range from 24°F to 104°F.
	Air – Outdoor (includes salt-laden atmospheric air and salt water spray)	
	Soil [Cracks and Distortion Due to Increased Stress Levels From Settlement]	
	Water - Flowing[Leaching of Calcium Hydroxide, Loss of Material, Loss Of Form]	
	Various [Elastomers III A6-12]	
Borated Water Leakage	Air With Borated Water Leakage [Supports]	The borated water leakage environment applies in plant indoor and outdoor areas that include components and systems that contain borated water and that could leak on nearby components or structures.
Encased in Concrete	Not a NUREG-1801 Structural Environment: See NUREG-1801 Mechanical Item	Components that are encased in concrete.

Structural Environments		
Evaluated Environment	**NUREG-1801 Environment**	**Description**
Buried (Structural)	Any [Reaction With Aggregates]	Structures/components that are buried in soil. Soil is a mixture of inorganic materials produced by the weathering of rocks and clays, and organic material produced by decomposition of vegetation. Voids containing air and moisture occupy about 50% of the soil volume. Properties of soil that can affect aging include water content, pH, ion exchange capacity, density, and permeability. The groundwater has been determined to be non-aggressive. Structures/components that are buried and may be exposed to: • Soil, dry under normal conditions • Soil with ground water present • Flowing water causing possible leaching condition • Foundation aging • Soft soil and settlement issues • An aggressive environment caused by contaminants in the soil
	Groundwater/Soil	
	Soil [Cracks and Distortion Due to Increased Stress Levels From Settlement]	
	Water - Flowing [Leaching of Calcium Hydroxide]	
	Air – Outdoor [Freeze Thaw]	
	Water - Flowing Under Foundation [Porous Concrete Sub-foundation]	
	Various [Elastomers III A6-12]	
Submerged (Structural)	Water – Standing [Tanks, Earthen Water Control Structures, and Water Control Structures Metal Components]	Structures that are completely or partially covered, or structures that are partially filled (such as tanks, sumps, etc.) with: • Water (operating or process fluid) • Oil/fluids (lube, fuel, EHC, etc.) Structures that are exposed to flowing water conditions potentially causing: • Abrasion • Cavitation • Leaching • Loss Of Material • Loss of Form
	Water - Flowing (includes Raw Water which includes untreated salt water) [Abrasion/Cavitation (concrete), Earthen Water Control Structures, and Water Control Structures Metal Components]	
	Treated Water or Treated Borated Water [Fuel Pool Liner]	
	Treated Water <60F (<140F) [Supports]	

Attachment C
Evaluated Electrical Environments

Electrical Environments		
Evaluated Environment	**NUREG-1801 Environment**	**Description**
Plant Indoor Air	Air Indoor	Indoor air on electrical components with temperatures higher than the dew point, i.e., condensation can occur but only rarely, equipment surfaces are normally dry.
Atmosphere/ Weather	Air Outdoors	The atmosphere/weather environment consists of moist, ambient temperatures, humidity, and exposure to weather, including precipitation and wind. The component is exposed to air and local weather conditions including salt spray. Temperature extremes range from 24°F to 104°F. There is no exposure to industry air pollution or other aggressive contaminants.
Borated Water Leakage	Air with Borated Water Leakage	The borated water leakage environment applies in plant indoor and outdoor areas that include components and systems that contain borated water and that could leak on nearby components or structures.
Adverse Localized Environment	Adverse localized environment caused by heat, radiation, or moisture in the presence of oxygen	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.

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Aluminum
(Includes cast aluminum and aluminum alloys)

ENVIRONMENT/FLUID: Air/Gas

AGING MECHANISM	AGING EFFECT	APPLICABILITY	REFERENCES	NUREG-1801
Boric Acid Corrosion (Wastage)	Loss of Material	Exposed to boric acid leakage.	EPRI TR-1003056	VII.A3-4, VII.E1-10
Crevice Corrosion	Loss of Material	Component susceptible to wetted environment (condensation) and a potential for concentrating contaminants exists.	EPRI 1003056, Appendix D, Section 3.1.3	VII.F1-14, VII.F2-12, VII.F3-14, VII.F4-10
Pitting Corrosion	Loss of Material	Component susceptible to wetted environment (condensation) and a potential for concentrating contaminants exists.	EPRI 1003056, Appendix D, Section 3.1.4	VII.F1-14, VII.F2-12, VII.F3-14, VII.F4-10

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Aluminum
(Includes cast aluminum and aluminum alloys)

ENVIRONMENT/FLUID: Treated Water and/or Steam

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Cracking	Stress Corrosion Cracking	For Aluminum Alloys only: O2 > 100 ppb and a Corrosive Environment.	EPRI 1003056, Appendix A, Section 3.2.2	None
Loss of Material	Crevice Corrosion	O2 > 100 ppb	EPRI 1003056, Appendix A, Section 3.1.4	VIII.D1-1, VIII.E-15, VIII.F-12, VIII.G-17
Loss of Material	Erosion	Material is subject to high velocity, constricted flow, or fluid direction change and fluid contains particulates (single phase) or water droplets (two phase flow).	EPRI 1003056, Appendix A, Section 3.1.6	None
Loss of Material	Flow-Accelerated Corrosion	Applicable for all in scope system components in the FAC program.	EPRI 1003056, Appendix A, Section 3.1.6	None
Loss of Material	Galvanic corrosion	Contact with metal higher in the galvanic series.	EPRI 1003056, Appendix A, Section 3.1.3	None
Loss of Material	Microbiologically Influenced Corrosion	Potential for MIC contamination and pH < 10 and temperature < 210°F.	EPRI 1003056, Appendix A, Section 3.1.7	None
Loss of Material	Pitting Corrosion	O2 > 100 ppb, corrosive environment, and Low Flow (< 3 fps).	EPRI 1003056, Appendix A, Section 3.1.5	VIII.D1-1, VIII.E-15, VIII.F-12, VIII.G-17

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Boraflex

ENVIRONMENT/FLUID: Treated Borated Water

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Reduction of Neutron-Absorbing Capacity	Boraflex Degradation	Spent Fuel Storage Racks. Neutron Absorbing Sheets.	NRC Information Notice 95-38, "Degradation of Boraflex Neutron Absorbed in Spent Fuel Storage Racks, September 8, 1995, United States Nuclear Regulatory Commission NRC Generic Letter 96-04: "Boraflex Degradation in Spent Fuel Pool Storage Racks," June 26,1996, United States Nuclear Regulatory Commission	VII.A2-4

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Boral, Boron Steel

ENVIRONMENT/FLUID: Treated Borated Water

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Loss of Material	General Corrosion	Spent Fuel Storage Racks. Neutron Absorbing Sheets. (Boron Steel only)	Plant Specific TR-8, Section 7.4	VII.A2-3, VII.A2-5
Reduction of Neutron-Absorbing Capacity	Reduction of Neutron-Absorbing Capacity	Spent Fuel Storage Racks. Neutron Absorbing Sheets.	Plant Specific TR-8, Section 7.4	VII.A2-3, VII.A2-5

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Carbon Steel, Low-Alloy Steel, and Cast Iron
(Includes galvanized, the manganese-molybdenum alloy, and the chrome-molybdenum alloy)

ENVIRONMENT/FLUID: Air/Gas /Indoor Air/Ventilation Atmosphere

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Loss of Material	Boric Acid Corrosion (Wastage)	Exposed to boric acid leakage.	EPRI 1003056, Appendix F, Section 3.3	IV.A2-13, IV.C2-9, IV.D1-3, V.A-3, V.A-4, V.D1-1, V.E-2, V.E-9, VII.A3-2, VII.E1-1, VII.I-2, VII.I-10, VIII.H-2, VIII.H-9
Loss of Material	Crevice Corrosion	INTERNAL: Replacement gas for fluorocarbons used, replacement gas is corrosive or gas is not dried air, N2, CO2, H2, or fluorocarbons and component susceptible to wetted environment and a potential for concentrating contaminants exists. EXTERNAL: Temperature < 212°F, material not in a controlled, air conditioned environment and surface exposed to an aggressive environment.	EPRI 1003056, Appendix D, Section 3.1.3 EPRI 1003056, Appendix E, Section 3.1.3	V.A-2, V.A-3, V.E-4, VII.A1-1, VII.D-1, VII.F1-3, VII.F1-10, VII.F2-3, VII.F2-8, VII.F3-3, VII.F3-10, VII.F4-2, VII.F4-7, VII.G-5, VII.G-23, VII.H2-3, VII.H2-21, VII.I-4, VIII.B1-7, VIII.G-34, VIII.H-4
Cracking	Cyclic Loading/Fatigue	Closure Bolting: Air with steam or water leakage. Pressurizer Integral Support: Air with metal temperature up to 288°C (550°F).	EPRI 1003056, Appendix F, Section 3.1.2 TBD	IV.C2-16, V.E-3, VII.E1-8, VII.I-3, VIII.H-3
Cracking (Cumulative Fatigue Damage)	Fatigue	Fatigue will be addressed in a TLAA evaluation.	Refer to TLAA.	IV.A2-4, IV.A2-20, VII.B-2, VII.E1-18,
Loss of Material	Galvanic Corrosion	INTERNAL: Gas is not dried air, N2, CO2, H2, or fluorocarbons and material contact with a metal higher in the galvanic series. EXTERNAL: Temperature < 212°F, material not in a controlled, air conditioned environment and component electrolytically connected to a dissimilar metal.	EPRI 1003056, Appendix D, Section 3.1.4 EPRI 1003056, Appendix E, Section 3.1.4	None

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Carbon Steel, Low-Alloy Steel, and Cast Iron
(Includes galvanized, the manganese-molybdenum alloy, and the chrome-molybdenum alloy)

ENVIRONMENT/FLUID: Air/Gas /Indoor Air/Ventilation Atmosphere (Continued)

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Loss of Material	General Corrosion	INTERNAL: Gas is not dried air, N2, CO2, H2, or fluorocarbons. EXTERNAL: Temperature < 212°F, material not in a controlled, air conditioned environment and surface is not buried or surface is buried and surface is exposed to an aggressive environment. EXTERNAL GALVANIZED: Temperature < 212°F, material not in a controlled, air conditioned environment and component buried or subject to wetting other than humidity and pH > 12 or pH < 6 or temperature > 140°F and < 200°F	EPRI 1003056, Appendix D, Section 3.1.1 EPRI 1003056, Appendix E, Section 3.1.1	V.A-1, V.A-2, V.A-3, V.A-19, V.C-1, V.C-2, V.E-4, V.E-6, V.E-7, V.E-10, VII.A1-1, VII.B-3, VII.D-1, VII.D-2, VII.D-3, VII.F1-2, VII.F1-3, VII.F1-4, VII.F1-10, VII.F2-2, VII.F2-3, VII.F2-4, VII.F2-8, VII.F3-2, VII.F3-3, VII.F3-4, VII.F3-10, VII.F4-1, VII.F4-2, VII.F4-3, VII.F4-7, VII.G-5, VII.G-23, VII.H2-3, VII.H2-21, VII.I-4, VII.I-6, VII.I-7, VII.I-8, VII.I-11, VIII.B1-7, VIII.G-34, VIII.H-4, VIII.H-6, VIII.H-7, VIII.H-10
Loss of Material	Microbiologically Influenced Corrosion	INTERNAL: Gas is not dried air, N2, CO2, H2, or fluorocarbons, component susceptible to wetted environment and potential source of MIC. EXTERNAL: Temperature < 212°F, material not in a controlled, air conditioned environment, surface is buried and surface is exposed to an aggressive environment.	EPRI 1003056, Appendix D, Section 3.1.6 EPRI 1003056, Appendix E, Section 3.1.6	VII.F1-3, VII.F2-3, VII.F3-3, VII.F4-2
Loss of Material	Pitting Corrosion	INTERNAL: Replacement gas for fluorocarbons used, replacement gas is corrosive or gas is not dried air, N2, CO2, H2, or fluorocarbons, component susceptible to wetted environment and a potential for concentrating contaminants exists. EXTERNAL: Temperature < 212°F, material not in a controlled, air conditioned environment and surface exposed to an aggressive environment.	EPRI 1003056, Appendix D, Section 3.1.4 EPRI 1003056, Appendix E, Section 3.1.4	V.A-2, V.A-3, V.E-4, VII.A1-1, VII.D-1, VII.D-2, VII.F1-3, VII.F1-10, VII.F2-3, VII.F2-8, VII.F3-3, VII.F3-10, VII.F4-2, VII.F4-7, VII.G-5, VII.G-23, VII.H2-3, VII.H2-21, VII.I-4, VIII.B1-7, VIII.G-34, VIII.H-4

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Carbon Steel, Low-Alloy Steel, and Cast Iron
(Includes galvanized, the manganese-molybdenum alloy, and the chrome-molybdenum alloy)

ENVIRONMENT/FLUID: Air/Gas /Indoor Air/Ventilation Atmosphere (Continued)

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Loss of Material	Selective Leaching	INTERNAL: Gas is not dried air, N2, CO2, H2, or fluorocarbons, component susceptible to wetted environment and material is gray cast iron. EXTERNAL: Temperature < 212°F, material not in a controlled, air conditioned environment, surface is exposed to aggressive environment and material is gray cast iron.	EPRI 1003056, Appendix D, Section 3.2.2	None
Cracking	Stress Corrosion Cracking	High strength low alloy steel bolting exposed to steam, water, or boric acid leakage.	EPRI 1003056, Appendix F, Section 3.2	IV.A2-2, IV.C2-7, IV.D1-2, V.E-3, VII.E1-8, VII.I-3, VIII.H-3
Loss of Preload	Stress Relaxation	Applicable for bolted closures.	EPRI 1003056, Appendix F, Section 3.1	IV.C2-8, V.E-5, VII.I-5, VIII.H-5
Loss of Material	Wear	Relative motion between surfaces (External)	EPRI 1003056, Appendix E, Section 3.1.7.	IV.A2-3, VII.B-1, VII.G-3
Reduction in Fracture Toughness	Radiation Embrittlement	Fluence $>10^{17}$ neutrons/cm^2. Applicable only for components inside the primary shield wall.	EPRI 1003056, Appendix A, Section 3.3.2	None

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Carbon Steel, Low-Alloy Steel, and Cast Iron
(Includes galvanized, the manganese-molybdenum alloy, and the chrome-molybdenum alloy)

ENVIRONMENT/FLUID: Atmosphere/Outdoor Air/Weather

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Loss of Material	Boric Acid Wastage	Exposed to boric acid leakage.	EPRI 1003056, Appendix F, Section 3.3	None
Loss of Material	Crevice Corrosion	Temperature < 212°F, material not in a controlled, air conditioned environment and surface exposed to an aggressive environment.	EPRI 1003056, Appendix E, Section 3.1.3	V.E-1, VII.G-6, VII.H1-8, VII.H1-11, VII.H2-4, VII.I-1, VIII.B1-6, VIII.E-39, VIII.G-40, VIII.H-1
Loss of Material	Galvanic Corrosion	Temperature < 212°F, material not in a controlled, air conditioned environment and component electrolytically connected to a dissimilar metal.	EPRI 1003056, Appendix E, Section 3.1.2	None
Loss of Material	General Corrosion	Temperature < 212°F, material not in a controlled, air conditioned environment, surface is not buried or surface is buried and surface is exposed to an aggressive environment. GALVANIZED: Temperature < 212°F, material not in a controlled, air conditioned environment, component buried or subject to wetting other than humidity and pH > 12 or pH < 6 or temperature > 140°F and < 200°F.	EPRI 1003056, Appendix E, Section 3.1.1	V.E-1, V.E-8, VII.G-6, VII.H1-8, VII.H1-11, VII.H2-4, VII.I-1, VII.I-9, VIII.B1-6, VIII.E-39, VIII.G-40, VIII.H-1, VIII.H-8
Loss of Material	Microbiologically Influenced Corrosion	Temperature < 212°F, material not in a controlled, air conditioned environment, surface is not buried and surface is exposed to an aggressive environment.	EPRI 1003056, Appendix E, Section 3.1.6	None
Loss of Material	Pitting Corrosion	Temperature < 212°F, material not in a controlled, air conditioned environment and surface exposed to an aggressive environment.	EPRI 1003056, Appendix E, Section 3.1.4	V.E-1, VII.G-6, VII.H1-8, VII.H1-11, VII.H2-4, VII.I-1, VIII.B1-6, VIII.E-39, VIII.G-40, VIII.H-1
Loss of Material	Selective Leaching	Temperature < 212°F, material not in a controlled, air conditioned environment, surface is exposed to aggressive environment and material is gray cast iron.	EPRI 1003056, Appendix E, Section 3.1.9	None
Loss of Material	Wear	Relative motion between surfaces (External)	EPRI 1003056, Appendix E, Section 3.1.7.	VII.G-4
Loss of Preload	Stress Relaxation	Applicable for bolted closures.	EPRI 1003056, Appendix F, Section 3.1	None

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Carbon Steel, Low-Alloy Steel, and Cast Iron
(Includes galvanized, the manganese-molybdenum alloy, and the chrome-molybdenum alloy)

ENVIRONMENT/FLUID: Oil

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Heat Transfer Degradation	Fouling	Applicable for heat exchanger tubes when potential for accumulation of deposits (sediment, silt, dust, corrosion products, micro- or macro-organisms, etc.) exists.	EPRI 1003056, Appendix G, Table 6-6	V.A-17, V.D1-12, VIII.G-15
Loss of Material	Crevice Corrosion	Presence of water contamination (Lube Oil Only) and potential for water pooling / separation	EPRI 1003056, Appendix C, Section 3.1.3	V.A-25, V.D1-28, VII.C1-17, VII.C2-13, VII.E1-19, VII.F1-19, VII.F2-17, VII.F3-19, VII.F4-15, VII.G-21, VII.G-22, VII.G-26, VII.G-27, VII.H1-10, VII.H2-5, VII.H2-20, VII.H2-24, VIII.A-14, VIII.D1-6, VIII.E-32, VIII.G-6, VIII.G-35
Loss of Material	Fretting	Applicable for the exterior of heat exchanger tubes.	EPRI 1003056, Appendix G, Table 6-6	None
Loss of Material	Galvanic corrosion	Presence of water contamination (Lube Oil Only), Potential for water pooling / separation and contact with a metal higher in the galvanic series.	EPRI 1003056, Appendix C, Section 3.1.2	None
Loss of Material	General Corrosion	Presence of water contamination (Lube Oil Only) and potential for water pooling / separation	EPRI 1003056, Appendix C, Section 3.1.1	V.A-25, V.D1-28, VII.C1-17, VII.C2-13, VII.E1-19, VII.F1-19, VII.F2-17, VII.F3-19, VII.F4-15, VII.G-21, VII.G-22, VII.G-26, VII.G-27, VII.H1-10, VII.H2-5, VII.H2-20, VII.H2-24, VIII.A-14, VIII.D1-6, VIII.E-32, VIII.G-6, VIII.G-35
Loss of Material	Microbiologically Influenced Corrosion	Fuel Oil: Always a concern. Lubricating Oil: To be evaluated based on plant specific operating experience.	EPRI 1003056, Appendix C, Section 3.1.6	VII.H1-10, VII.H2-5, VII.H2-24, VIII.G-6

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Carbon Steel, Low-Alloy Steel, and Cast Iron
(Includes galvanized, the manganese-molybdenum alloy, and the chrome-molybdenum alloy)

ENVIRONMENT/FLUID: Oil (Continued)

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Loss of Material	Pitting Corrosion	Presence of water contamination (Lube Oil Only) and potential for water pooling / separation	EPRI 1003056, Appendix C, Section 3.1.4	V.A-25, V.D1-28, VII.C1-17, VII.C2-13, VII.E1-19, VII.F1-19, VII.F2-17, VII.F3-19, VII.F4-15, VII.G-21, VII.G-22, VII.G-26, VII.G-27, VII.H1-10, VII.H2-5, VII.H2-20, VII.H2-24, VIII.A-14, VIII.D1-6, VIII.E-32, VIII.G-6, VIII.G-35
Loss of Material	Selective Leaching	Presence of water contamination (Lube Oil Only), potential for water pooling / separation and material is gray cast iron.	EPRI 1003056, Appendix C, Section 3.1.8	None
Loss of Material	Fouling	Subject to accumulation of deposits (sediment, silt, dust, corrosion products, micro- or macro-organisms, etc.)	TBD	VII.H1-10, VII.H2-5, VII.H2-24

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Carbon Steel, Low-Alloy Steel, and Cast Iron
(Includes galvanized, the manganese-molybdenum alloy, and the chrome-molybdenum alloy)

ENVIRONMENT/FLUID: Raw Water

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Heat Transfer Degradation	Fouling	Applicable for heat exchanger tubes when potential for accumulation of deposits (sediment, silt, dust, corrosion products, micro- or macro-organisms, etc.) exists.	EPRI 1003056, Appendix G, Table 6-5	VIII.G-16
Loss of Material	Fouling	Subject to accumulation of deposits (sediment, silt, dust, corrosion products, micro- or macro-organisms, etc.)	TBD	V.A-10, V.C-5, V.D1-7, VII.C1-5, VII.C1-19, VII.C3-10, VII.G-24, VII.H2-22, VIII.E-6, VIII.F-5, VIII.G-7, VIII.G-36
Loss of Material	Crevice Corrosion	Always.	EPRI 1003056, Appendix B, Section 3.1.4	V.A-10, V.C-5, V.D1-7, VII.C1-5, VII.C1-19, VII.C3-10, VII.G-24, VII.H2-22, VIII.E-6, VIII.F-5, VIII.G-7, VIII.G-36
Loss of Material	Erosion	Subject to high velocities, constricted flow, or fluid direction change.	EPRI 1003056, Appendix B, Section 3.1.6	None
Loss of Material	Fretting	Applicable for the exterior of heat exchanger tubes.	EPRI 1003056, Appendix G, Table 6-5	None
Loss of Material	Galvanic corrosion	Contact with metal higher in the galvanic series.	EPRI 1003056, Appendix B, Section 3.1.3	V.A-10, V.D1-7, VII.C1-5, VIII.E-6, VIII.F-5, VIII.G-7, VIII.G-36
Loss of Material	General Corrosion	Always.	EPRI 1003056, Appendix B, Section 3.1.1	V.A-10, V.C-5, V.D1-7, VII.C1-5, VII.C1-19, VII.C3-10, VII.G-24, VII.H2-22, VIII.E-6, VIII.F-5, VIII.G-7, VIII.G-36
Loss of Material	Lining or Coating Degradation	The Aging Management Review (AMR) methodology does not take credit for coatings and/or linings.	TR-8, Section 6.1	VII.C1-19, VII.C3-10, VII.H2-22
Loss of Material	Microbiologically Influenced Corrosion	pH < 10.	EPRI 1003056, Appendix B, Section 3.1.5	V.A-10, V.C-5, V.D1-7, VII.C1-5, VII.C1-19, VII.C3-10, VII.G-24, VII.H2-22, VIII.E-6, VIII.F-5, VIII.G-7, VIII.G-36

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Carbon Steel, Low-Alloy Steel, and Cast Iron
(Includes galvanized, the manganese-molybdenum alloy, and the chrome-molybdenum alloy)

ENVIRONMENT/FLUID: Raw Water (Continued)

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Loss of Material	Pitting Corrosion	Low Flow (< 3 fps).	EPRI 1003056, Appendix B, Section 3.1.2	V.A-10, V.C-5, V.D1-7, VII.C1-5, VII.C1-19, VII.C3-10, VII.G-24, VII.H2-22, VIII.E-6, VIII.F-5, VIII.G-7, VIII.G-36
Loss of Material	Selective Leaching	Material is gray cast iron.	EPRI 1003056, Appendix B, Section 3.1.2	VII.C1-11, VII.C3-4, VII.G-14, VII.H2-14, VIII.A-7, VIII.G-24

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Carbon Steel, Low-Alloy Steel, and Cast Iron
(Includes galvanized, the manganese-molybdenum alloy, and the chrome-molybdenum alloy)

ENVIRONMENT/FLUID: Soil

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Loss of Material	Crevice Corrosion	Always when exposed to ground water.	EPRI 1003056, Appendix E, Table 4-1	VII.C1-18, VII.C3-9, VII.G-25, VII.H1-9, VIII.E-1, VIII.G-1
Loss of Material	General Corrosion	Always when exposed to ground water.	EPRI 1003056, Appendix E, Table 4-1	VII.C1-18, VII.C3-9, VII.G-25, VII.H1-9, VIII.E-1, VIII.G-1
Loss of Material	Lining or Coating Degradation	The Aging Management Review (AMR) methodology does not take credit for coatings and/or linings.	TR-8, Section 6.1	None
Loss of Material	Microbiologically Influenced Corrosion	Always when exposed to ground water with pH < 10.	EPRI 1003056, Appendix E, Table 4-1	VII.C1-18, VII.C3-9, VII.G-25, VII.H1-9, VIII.E-1, VIII.G-1
Loss of Material	Pitting Corrosion	Always when exposed to ground water with Low Flow (< 3 fps).	EPRI 1003056, Appendix E, Table 4-1	VII.C1-18, VII.C3-9, VII.G-25, VII.H1-9, VIII.E-1, VIII.G-1
Loss of Material	Selective Leaching	Always when exposed to ground water and material is gray cast iron.	EPRI 1003056, Appendix E, Table 4-1	V.D1-21, VII.C1-12, VII.C3-5, VII.G-15, VII.H1-5, VII.H2-15, VIII.E-22, VIII.G-25

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Carbon Steel, Low-Alloy Steel, and Cast Iron
(Includes galvanized, the manganese-molybdenum alloy, and the chrome-molybdenum alloy)

ENVIRONMENT/FLUID: Treated Water and/or Steam

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Cracking	Stress Corrosion Cracking	Potential for MIC contamination, pH < 10, temperature < 210°F, nitrite corrosion inhibitor in use and material is carbon or low alloy steel.	EPRI 1003056, Appendix A, Section 3.2.2	None
Reduction of Heat Transfer / Heat Transfer Degradation	Fouling	Applicable for heat exchanger tubes when potential for accumulation of deposits (sediment, silt, dust, corrosion products, micro- or macro-organisms, etc.) exists.	EPRI 1003056, Appendix G, Table 6-3	VII.F1-13, VII.F2-11, VII.F3-13, VII.F4-9, VIII.A-2, VIII.E-14, VIII.F-11, VIII.G-14
Loss of Material	Crevice Corrosion	O2 >100 ppb.	EPRI 1003056, Appendix A, Section 3.1.4	IV.C2-14, IV.D1-9, IV.D1-12, V.A-9, V.C-6, V.C-9, V.D1-6, VII.A3-3, VII.A3-9, VII.A4-3, VII.C2-1, VII.C2-14, VII.E1-6, VII.F1-11, VII.F1-20, VII.F2-9, VII.F2-18, VII.F3-11, VII.F3-20, VII.F4-8, VII.F4-16, VII.H2-23, VIII.A-1, VIII.A-16, VIII.B1-8, VIII.B1-11, VIII.C-4, VIII.C-7, VIII.D1-8, VIII.E-5, VIII.E-34, VIII.E-37, VIII.E-40, VIII.F-4, VIII.F-25, VIII.F-28, VIII.G-5, VIII.G-38, VIII.G-41
Cracking	Cyclic Loading	Underclad cracking may be present in SA508 Cl 2 reactor vessel forgings. Cracks in the pressurizer clad and the RCS piping/fittings can propagate into the base and weld metal. One source of cyclic loading is due to periodic application of pressure loads and forces due to thermal movement of piping transmitted through penetrations and structures to which penetrations are connected. The typical result of cyclic loads on metal components is fatigue cracking and failure; however, the cyclic loads may also cause deformation that results in functional failure.	WCAP-14422-A, Section 3.2.6 WCAP-14574-A, Section 3.1 WCAP-14575-A, Section 3.2.1	IV.A2-22, IV.C2-18, IV.C2-26
Loss of Material	Erosion	Material is subject to high velocity, constricted flow, or fluid direction change and fluid contains particulates (single phase) or water droplets (two phase flow).	EPRI 1003056, Appendix A, Section 3.1.6	IV.D1-9, IV.D1-13

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Carbon Steel, Low-Alloy Steel, and Cast Iron
(Includes galvanized, the manganese-molybdenum alloy, and the chrome-molybdenum alloy)

ENVIRONMENT/FLUID: Treated Water and/or Steam (Continued)

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Wall Thinning	Flow-Accelerated Corrosion	Applicable for all in-scope system components in the FAC program.	EPRI 1003056, Appendix A, Section 3.1.6	IV.D1-5, IV.D1-16, IV.D1-26, VIII.A-17, VIII.B1-9, VIII.C-5, VIII.D1-9, VIII.E-35, VIII.F-26, VIII.G-39
Loss of Material	Fretting	Applicable for the exterior of heat exchanger tubes.	EPRI 1003056, Appendix G, Table 6-3	None
Loss of Material	Galvanic corrosion	Contact with metal higher in the galvanic series.	EPRI 1003056, Appendix A, Section 3.1.3	V.A-9, V.D1-6, VII.A3-3, VII.A4-3, VII.C2-1, VII.E1-6, VII.F1-11, VII.F2-9, VII.F3-11, VII.F4-8, VIII.A-1, VIII.E-5, VIII.F-4, VIII.G-5
Loss of Material	General Corrosion	Material is carbon steel, low alloy steel, or cast iron.	EPRI 1003056, Appendix A, Section 3.1.1	IV.C2-14, IV.D1-9, IV.D1-12, V.A-9, V.C-6, V.C-9, V.D1-6, VII.A3-3, VII.A4-3, VII.C2-1, VII.C2-14, VII.E1-6, VII.F1-11, VII.F1-20, VII.F2-9, VII.F2-18, VII.F3-11, VII.F3-20, VII.F4-8, VII.F4-16, VII.H2-23, VIII.A-1, VIII.A-16, VIII.B1-11, VIII.C-4, VIII.C-7, VIII.D1-8, VIII.E-5, VIII.E-34, VIII.E-37, VIII.E-40, VIII.F-4, VIII.F-25, VIII.F-28, VIII.G-5, VIII.G-38, VIII.G-41
Loss of Material	Microbiologically Influenced Corrosion	Potential for MIC contamination and pH < 10 and temperature < 210°F.	EPRI 1003056, Appendix A, Section 3.1.7	None

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Carbon Steel, Low-Alloy Steel, and Cast Iron
(Includes galvanized, the manganese-molybdenum alloy, and the chrome-molybdenum alloy)

ENVIRONMENT/FLUID: Treated Water and/or Steam (Continued)

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Loss of Material	Pitting Corrosion	O2 > 100 ppb, corrosive environment and low flow (< 3 fps).	EPRI 1003056, Appendix B, Section 3.1.5	IV.C2-14, IV.D1-9, IV.D1-12, V.A-9, V.C-6, V.C-9, V.D1-6, VII.A3-3, VII.A3-9, VII.A4-3, VII.C2-1, VII.C2-14, VII.E1-6, VII.F1-11, VII.F1-20, VII.F2-9, VII.F2-18, VII.F3-11, VII.F3-20, VII.F4-8, VII.F4-16, VII.H2-23, VIII.A-1, VIII.A-16, VIII.B1-8, VIII.B1-11, VIII.C-4, VIII.C-7, VIII.D1-8, VIII.E-5, VIII.E-34, VIII.E-37, VIII.E-40, VIII.F-4, VIII.F-25, VIII.F-28, VIII.G-5, VIII.G-38, VIII.G-41
Loss of Material	Selective Leaching	Material is gray cast iron.	EPRI 1003056, Appendix B, Section 3.1.2	V.A-18, V.D1-13 , V.D1-20, VII.A3-7, VII.C2-8, VII.C2-9, VII.E1-14, VII.F1-18, VII.F2-16, VII.F3-18, VII.F4-14, VII.G-16, VIII.A-8, VIII.E-23, VIII.F-19, VIII.G-26
Cumulative Fatigue damage	Fatigue	Fatigue is to be addressed in a TLAA evaluation.	Refer to TLAA	IV.A2-21, IV.C2-10, IV.C2-23, IV.C2-25, IV.D1-8, IV.D1-11, VIII.B1-10, VIII.D1-7, VIII.G-37
Cracking	Thermal and Mechanical Loading	Applicable to the RCS and lines connected to the RCS.	WCAP-14575-A, Section 3.2.1	IV.C2-1

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Carbon Steel, Low-Alloy Steel, and Cast Iron
(Includes galvanized, the manganese-molybdenum alloy, and the chrome-molybdenum alloy)

ENVIRONMENT/FLUID: Treated Water and/or Steam (Continued)

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Reduction in Fracture Toughness	Radiation Embrittlement	Fluence $>10^{17}$ neutrons/cm^2. Applicable only for components inside the primary shield wall.	EPRI 1003056, Appendix A, Section 3.3.2	IV.A2-16, IV.A2-17, IV.A2-23, IV.A2-24
Loss of Material	Wear	Relative motion between surfaces. Applicable to Reactor Vessel Flange.	WCAP-14581, Section 3.2.5	IV.A2-25
Stress Relaxation / Thermal Effects, Gasket Creep, and Self-Loosening	Loss of Preload	Applicable for bolted closures.	EPRI 1003056, Appendix F, Section 3.1	IV.D1-10
Loss of Material	Cladding Breach	Only applicable for pump casings in the reactor coolant system made from carbon steel with a stainless steel cladding.	NRC Information Notice 94-63, “Boric Acid Corrosion of Charging Pump Casings Caused by Cladding Cracks."	V.D1-32, VII.E1-21

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Copper Alloys
(Including brass, bronze, aluminum-bronze, and copper-nickel)

ENVIRONMENT/FLUID: Air/Gas

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Cracking	Stress Corrosion Cracking	Gas is not dried air, N_2, CO_2, H_2 or fluorocarbons, component susceptible to wetted environment and a potential for concentrating contaminants exists.	EPRI 1003056, Appendix D, Section 3.2.2	None
Heat Transfer Degradation	Fouling	Applicable for heat exchanger tubes when potential for accumulation of deposits (sediment, silt, dust, corrosion products, etc.) exists.	EPRI 1003056, Appendix G, Table 6-7	None
Loss of Material	Boric Acid Wastage	Exposed to boric acid leakage (Zn > 15%).	TR-104748S, Boric Acid Corrosion Guidebook	V.E-11, VII.I-12
Loss of Material	Crevice Corrosion	INTERNAL: Replacement gas for fluorocarbons used, replacement gas is corrosive or gas is not dried air, N_2, CO_2, H_2 or fluorocarbons, component susceptible to wetted environment and a potential for concentrating contaminants exists. EXTERNAL: Temperature < 212°F, material not in a controlled, air conditioned environment and surface is exposed to aggressive environment.	EPRI 1003056, Appendix D, Section 3.1.3 EPRI 1003056, Appendix E, Section 3.1.3	VII.F1-16, VII.F2-14, VII.F3-16, VII.F4-12, VII.G-9
Loss of Material	Fretting	Applicable for the exterior of heat exchanger tubes.	EPRI 1003056, Appendix G, Table 6-7	None
Loss of Material	Galvanic corrosion	Gas is not dried air, N_2, CO_2, H_2 or fluorocarbons and material contact with a metal higher in the galvanic series.	EPRI 1003056, Appendix D, Section 3.1.3	None
Loss of Material	Microbiologically Influenced Corrosion	Gas is not dried air, N_2, CO_2, H_2 or fluorocarbons, component susceptible to wetted environment and potential source of MIC.	EPRI 1003056, Appendix D, Section 3.1.6	None
Loss of Material	Pitting Corrosion	INTERNAL: Replacement gas for fluorocarbons used, replacement gas is corrosive or gas is not dried air, N_2, CO_2, H_2 or fluorocarbons, component susceptible to wetted environment and a potential for concentrating contaminants exists. EXTERNAL: Temperature < 212°F, material not in a controlled, air conditioned environment and surface is exposed to aggressive environment.	EPRI 1003056, Appendix D, Section 3.1.4 EPRI 1003056, Appendix E, Section 3.1.4	VII.F1-16, VII.F2-14, VII.F3-16, VII.F4-12, VII.G-9

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Copper Alloys
(Including brass, bronze, aluminum-bronze, and copper-nickel)

ENVIRONMENT/FLUID: Air/Gas (Continued)

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Loss of Material	Selective Leaching	MATERIAL: Copper Alloy must include >15% Zn or > 8% Al INTERIOR: Gas is not dried air, N_2, CO_2, H_2 or fluorocarbons and component susceptible to wetted environment EXTERNAL: Temperature < 212°F, material not in a controlled, air conditioned environment and surface is exposed to aggressive environment.	EPRI 1003056, Appendix D, Section 3.1.8 EPRI 1003056, Appendix E, Section 3.1.9	None
Loss of Material	Wear	Relative motion between surfaces (External)	EPRI 1003056, Appendix E, Section 3.1.7.	None

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Copper Alloys
(Including brass, bronze, aluminum-bronze, and copper-nickel)

ENVIRONMENT/FLUID: Atmosphere/Weather

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Loss of Material	Crevice Corrosion	Temperature < 212°F, material not in a controlled, air conditioned environment and surface is exposed to aggressive environment.	EPRI 1003056, Appendix D, Section 3.1.3	None
Loss of Material	Galvanic corrosion	Contact with metal higher in the galvanic series.	EPRI 1003056, Appendix D, Section 3.1.2	None
Loss of Material	Microbiologically Influenced Corrosion	Temperature < 212°F, material not in a controlled, air conditioned environment, surface is exposed to aggressive environment and surface is buried.	EPRI 1003056, Appendix D, Section 3.1.6	None
Loss of Material	Pitting Corrosion	Temperature < 212°F, material not in a controlled, air conditioned environment and surface is exposed to aggressive environment.	EPRI 1003056, Appendix D, Section 3.1.4	None
Loss of Material	Selective Leaching	MATERIAL: Copper Alloy must include >15% Zn or > 8% Al ENVIRONMENT: Temperature < 212°F, material not in a controlled, air conditioned environment and surface is exposed to aggressive environment.	EPRI 1003056, Appendix D, Section 3.1.9	None
Loss of Material	Wear	Relative motion between surfaces (External)	EPRI 1003056, Appendix E, Section 3.1.7.	None

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Copper Alloys
(Including brass, bronze, aluminum-bronze, and copper-nickel)

ENVIRONMENT/FLUID: Oil

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Cracking	Stress Corrosion Cracking/IGA	For Fuel Oil Only: Potential for water pooling / separation and O_2 > 100 ppb.	EPRI 1003056, Appendix C, Section 3.2.2	None
Heat Transfer Degradation	Fouling	Applicable for heat exchanger tubes when potential for accumulation of deposits (sediment, silt, dust, corrosion products, micro- or macro-organisms, etc.) exists.	EPRI 1003056, Appendix G, Table 6-6	V.A-12, V.D1-8, VIII.G-8
Loss of Material	Crevice Corrosion	Potential of water contamination (Lube Oil Only) and potential for water pooling / separation..	EPRI 1003056, Appendix C, Section 3.1.3	V.A-21, V.D1-19, VII.C1-8, VII.C2-5, VII.E1-12, VII.G-10, VII.G-11, VII.H1-3, VII.H2-9, VII.H2-10, VIII.A-3, VIII.D1-2, VIII.E-17, VIII.G-19
Loss of Material	Fretting	Applicable for the exterior of heat exchanger tubes.	EPRI 1003056, Appendix G, Table 6-6	None
Loss of Material	Galvanic corrosion	Potential of water contamination (Lube Oil Only), potential for water pooling / separation and contact with metal higher in the galvanic series.	EPRI 1003056, Appendix C, Section 3.1.2	None
Loss of Material	Microbiologically Influenced Corrosion	Always (Fuel Oil Only)	EPRI 1003056, Appendix C, Section 3.1.6	VII.G-10, VII.H1-3, VII.H2-9
Loss of Material	Pitting Corrosion	Potential of water contamination (Lube Oil Only) and potential for water pooling / separation.	EPRI 1003056, Appendix C, Section 3.1.4	V.A-21, V.D1-19, VII.C1-8, VII.C2-5, VII.E1-12, VII.G-10, VII.G-11, VII.H1-3, VII.H2-9, VII.H2-10, VIII.A-3, VIII.D1-2, VIII.E-17, VIII.G-19
Loss of Material	Selective Leaching	MATERIAL: Copper Alloy must include >15% Zn or > 8% Al ENVIRONMENT: Potential of water contamination and potential for water pooling / separation.	EPRI 1003056, Appendix C, Section 3.1.8	None

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Copper Alloys
(Including brass, bronze, aluminum-bronze, and copper-nickel)

ENVIRONMENT/FLUID: Raw Water

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Cracking	Stress Corrosion Cracking/IGA	Fluid contains ammonia or ammonium compound.	EPRI 1003056, Appendix B, Section 3.2.2	None
Heat Transfer Degradation	Fouling	Applicable for heat exchanger tubes when potential for accumulation of deposits (sediment, silt, dust, corrosion products, micro- or macro-organisms, etc.) exists.	EPRI 1003056, Appendix G, Table 6-5	VII.C1-6, VIII.E-9, VIII.F-6, VIII.G-9
Loss of Material	Fouling	Subject to accumulation of deposits (sediment, silt, dust, corrosion products, micro- or macro-organisms, etc.)	TBD	VII.C1-3, VII.C1-9, VII.G-12
Loss of Material	Crevice Corrosion	Always.	EPRI 1003056, Appendix B, Section 31.4	VII.C1-3, VII.C1-9, VII.C3-2, VII.G-12, VII.H2-11, VIII.A-4, VIII.E-18, VIII.F-14, VIII.G-20
Loss of Material	Erosion	Subject to high velocity, constricted flow, or fluid direction change.	EPRI 1003056, Appendix B, Section 3.1.6	None
Loss of Material	Fretting	Applicable for the exterior of heat exchanger tubes.	EPRI 1003056, Appendix G, Table 6-5	None
Loss of Material	Galvanic corrosion	Contact with metal higher in the galvanic series.	EPRI 1003056, Appendix B, Section 3.1.3	VII.C1-3
Loss of Material	Microbiologically Influenced Corrosion	pH < 10.	EPRI 1003056, Appendix B, Section 3.1.7	VII.C1-3, VII.C1-9, VII.G-12, VII.H2-11, VIII.A-4, VIII.E-18, VIII.F-14, VIII.G-20
Loss of Material	Pitting Corrosion	Stagnant or Low Flow (< 3fps).	EPRI 1003056, Appendix B, Section 3.1.5	VII.C1-3, VII.C1-9, VII.C3-2, VII.G-12, VII.H2-11, VIII.A-4, VIII.E-18, VIII.F-14, VIII.G-20
Loss of Material	Selective Leaching	Copper Alloy must contain >15% Zn or > 8% Al.	EPRI 1003056, Appendix B, Section 3.1.2	VII.C1-4, VII.C1-10, VII.C3-3, VII.G-13, VII.H2-13, VIII.A-6, VIII.E-20, VIII.F-17, VIII.G-22

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Copper Alloys
(Including brass, bronze, aluminum-bronze, and copper-nickel)

ENVIRONMENT/FLUID: Treated Water and/or Steam

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Cracking	Stress Corrosion Cracking/IGA	Fluid contains ammonia or ammonium compound and 02 > 100 ppb.	EPRI 1003056, Appendix A, Section 3.2.2	None
Heat Transfer Degradation	Fouling	Applicable for heat exchanger tubes when potential for accumulation of deposits (sediment, silt, dust, corrosion products, micro- or macro-organisms, etc.) exists.	EPRI 1003056, Appendix G, Table 6-3	V.A-11, VII.C2-2, VII.F1-12, VII.F2-10, VII.F3-12, VIII.E-8, VIII.E-10, VIII.F-7, VIII.G-10
Loss of Material	Crevice Corrosion	O2 >100 ppb.	EPRI 1003056, Appendix A, Section 3.1.4	IV.C2-11, V.A-5, V.A-20, V.D1-2, V.D1-17, VII.A3-5, VII.C2-4, VII.E1-2, VII.E1-11, VII.F1-8, VII.F1-15, VII.F2-13, VII.F3-8, VII.F3-15, VII.F4-11, VII.H1-2, VII.H2-8, VIII.A-5, VIII.E-16, VIII.F-13, VIII.F-15, VIII.G-18
Loss of Material	Erosion	Subject to high velocity, constricted flow, or fluid direction change and fluid contains particulates (single phase) or water droplets (two phase flow).	EPRI 1003056, Appendix A, Section 3.1.6	None
Loss of Material	Flow-Accelerated Corrosion	Applicable for all inscope system components in the FAC program.	EPRI 1003056, Appendix A, Section 3.1.6	None
Loss of Material	Fretting	Applicable for the exterior of heat exchanger tubes.	EPRI 1003056, Appendix G, Table 6-3	None
Loss of Material	Galvanic corrosion	Contact with metal higher in the galvanic series.	EPRI 1003056, Appendix A, Section 3.1.3	IV.C2-11, V.A-5, V.A-20, V.D1-2, V.D1-17, VII.A3-5, VII.C2-4, VII.E1-2, VII.E1-11, VII.F1-8, VII.F1-15, VII.F2-13, VII.F3-8, VII.F3-15, VII.F4-11, VII.H1-2, VII.H2-8, VIII.E-16, VIII.F-13, VIII.G-18
Loss of Material	Microbiologically Influenced Corrosion	Potential for MIC contamination and pH < 10 and temperature < 210°F.	EPRI 1003056, Appendix A, Section 3.1.7	None

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Copper Alloys
(Including brass, bronze, aluminum-bronze, and copper-nickel)

ENVIRONMENT/FLUID: Treated Water and/or Steam (Continued)

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Loss of Material	Pitting Corrosion	O2 > 100 ppb, corrosive environment and low flow (< 3 fps).	EPRI 1003056, Appendix A, Section 3.1.5	IV.C2-11, V.A-5, V.A-20, V.D1-2, V.D1-17, VII.A3-5, VII.C2-4, VII.E1-2, VII.E1-11, VII.F1-8, VII.F1-15, VII.F2-13, VII.F3-8, VII.F3-15, VII.F4-11, VII.H1-2, VII.H2-8, VIII.A-5, VIII.E-16, VIII.F-13, VIII.F-15, VIII.G-18
Loss of Material	Selective Leaching	Copper alloy must contain >15% Zn or >8% Al.	EPRI 1003056, Appendix A, Section 3.1.2	IV.C2-12, V.A-6, V.A-22, V.D1-3, V.D1-19, VII.A3-6, VII.C2-6, VII.C2-7, VII.E1-3, VII.E1-13, VII.F1-9, VII.F1-17, VII.F2-15, VII.F3-9, VII.F3-17, VII.F4-13, VII.H1-4, VII.H2-12, VIII.E-19, VIII.E-21, VIII.F-16, VIII.F-18, VIII.G-21, VIII.G-23

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Nickel-Based Alloys
(Including alloy 600/690)

ENVIRONMENT/FLUID: Air/Gas

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Loss of Material	Crevice Corrosion	Replacement gas for fluorocarbons used, replacement gas is corrosive or gas is not dried air, N2, CO2, H2, or fluorocarbons, component susceptible to wetted environment and a potential for concentrating contaminants exists	EPRI 1003056, Appendix D, Section 3.1.3.	None
Loss of Material	Microbiologically Influenced Corrosion	Gas is not dried air, N2, CO2, H2, or fluorocarbons, component susceptible to wetted environment and potential source of MIC.	EPRI 1003056, Appendix D, Section 3.1.6	None
Loss of Material	Pitting Corrosion	Replacement gas for fluorocarbons used and replacement gas is corrosive or gas is not dried air, N2, CO2, H2, or fluorocarbons, component susceptible to wetted environment and a potential for concentrating contaminants exists.	EPRI 1003056, Appendix D, Section 3.1.4.	None
Loss of Material	Wear	Relative motion between surfaces (External)	EPRI 1003056, Appendix E, Section 3.1.7.	None

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Nickel-Based Alloys
(Including alloy 600/690)

ENVIRONMENT/FLUID: Raw Water

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG 1801
Loss of Material	Crevice Corrosion	O_2 >100 ppb.	EPRI 1003056, Appendix A, Section 3.1.4	VII.C1-13, VII.C3-6
Loss of Material	Pitting Corrosion	O_2>100 ppb, corrosive environment and low flow (< 3 fps).	EPRI 1003056, Appendix A, Section 3.1.5	VII.C1-13, VII.C3-6

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Nickel-Based Alloys (Including alloy 600/690)
ENVIRONMENT/FLUID: Treated Water and/or Steam

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG 1801
Loss of Material	Crevice Corrosion	O2 >100 ppb.	EPRI 1003056, Appendix A, Section 3.1.4	IV.A2-14, IV.B2-32, IV.B3-25, IV.B4-38, IV.C2-15, IV.D1-15, VIII.B1-1
Cracking	Cyclic Loading	Cracks in the pressurizer clad can propagate into the base and weld metal.	WCAP-14574-A, Section 3.1	IV.C2-18
Loss of Material	Microbiologically Influenced Corrosion	Potential for MIC contamination and pH < 10 and temperature < 210°F.	EPRI 1003056, Appendix A, Section 3.1.7	None
Loss of Material	Denting	Steam Generator Tubes.	WCAP-14757	IV.D1-19
Loss of Material	Erosion	Material is subject to high velocity, constricted flow, or fluid direction change and fluid contains particulates (single phase) or water droplets (two phase flow).	EPRI 1003056, Appendix A, Section 3.1.6	None
Cumulative Fatigue Damage	Fatigue	Fatigue is to be addressed in a TLAA evaluation.	Refer to TLAA.	IV.A2-21, IV.B2-31, IV.B3-24, IV.B4-37, IV.C2-25, IV.D1-8, IV.D1-21
Loss of Material	Fretting	Steam Generator Support Plates.	WCAP-14757, Section 3.3	IV.D1-15, IV.D1-24
Loss of Material	Pitting Corrosion	O2>100 ppb, corrosive environment (such as phosphate chemistry) and low flow (< 3 fps).	EPRI 1003056, Appendix A, Section 3.1.5	IV.A2-14, IV.B2-32, IV.B3-25, IV.B4-38, IV.C2-15, IV.D1-25, VIII.B1-1
Reduction in Fracture Toughness	Radiation Embrittlement	Fluence $>10^{17}$ neutrons/cm^2. Applicable only for components inside the primary shield wall.	EPRI 1003056, Appendix A, Section 3.3.2	IV.B2-17, IV.B3-10, IV.B3-20, IV.B4-12, IV.B4-16, IV.B4-24, IV.B4-31

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Nickel-Based Alloys (Including alloy 600/690)
ENVIRONMENT/FLUID: Treated Water and/or Steam (Continued)

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG 1801
Cracking	Stress Corrosion Cracking/IGA	O2 > 100 ppb or corrosive environment and temperatures > 500°F.	EPRI 1003056, Appendix A, Section 3.2.2	IV.A2-9, IV.A2-11, IV.A2-12, IV.A2-15, IV.A2-18, IV.A2-19, IV.B2-16, IV.B2-20, IV.B2-28, IV.B2-40, IV.B3-5, IV.B3-9, IV.B3-23, IV.B4-13, IV.B4-20, IV.B4-25, IV.B4-32, IV.C2-13, IV.C2-17, IV.C2-19, IV.C2-21, IV.C2-24, IV.D1-4, IV.D1-6, IV.D1-14, IV.D1-18, IV.D1-20, IV.D1-22, IV.D1-23
Change in Dimension	Void Swelling	Applicable for reactor vessel internals.	WCAP-14577, Section 3.1.11	IV.B2-15, IV.B2-17, IV.B2-19, IV.B2-27, IV.B2-39, IV.B3-4, IV.B3-8, IV.B3-10, IV.B3-13, IV.B3-19, IV.B3-20, IV.B4-11, IV.B4-12, IV.B4-16, IV.B4-17, IV.B4-23, IV.B4-24, IV.B4-30, IV.B4-31
Loss of Material	Wear	Relative motion between surfaces. Upper core plate alignment pins; Steam Generator tubes and sleeves.	WCAP-14577, Section 3.1.7 WCAP-14757, Section 3.4	IV.B2-34, IV.B3-22, IV.D1-24
Loss of Preload	Stress Relaxation	Applicable only for RVI.	WCAP-14577, Section 3.1.6	IV.B2-14, IV.B2-25, IV.B2-38, IV.B3-6, IV.B3-7, IV.B4-14, IV.B4-19, IV.B4-26, IV.B4-33

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Non-Metallic (Fiberglass, PVC)

ENVIRONMENT/FLUID: Air/Gas

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Reduced Strength	Ozone Exposure	Exposure to high levels of ozone that might be associated with high-voltage electrical equipment.	Engineered Materials Handbook, Volume 1, Composites, ASM Handbook Committee	None
Reduced Strength	Ultraviolet Exposure	Exposure to direct sun light.	Engineered Materials Handbook, Volume 2, Engineering Plastics, ASM Handbook Committee	None

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Non-Metallic (Fiberglass, PVC)

ENVIRONMENT/FLUID: Atmosphere/Weather

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Reduced Strength	Ozone Exposure	Exposure to high levels of ozone that might be associated with high-voltage electrical equipment.	Engineered Materials Handbook, Volume 1, Composites, ASM Handbook Committee	None
Reduced Strength	Ultraviolet Exposure	Exposure to direct sun light.	Engineered Materials Handbook, Volume 2, Engineering Plastics, ASM Handbook Committee	None

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Non-Metallic (Rubber)
(Rubber, butyl rubbers, fluorelastomers, neoprene, nitrile rubbers, silicone rubber, Viton, ethylene-propylene rubber [EPR]) and ethylene-propylene dienyl monomer [EPDM].

ENVIRONMENT/FLUID: Air/Gas

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Hardening and Loss of Strength	Elastomer Degradation	Applicable for exposures exceeding 10^6 rads total integrated dose over the period of extended operation. Applicable for temperatures >95°F	EPRI 1002950, Section 7.3.1	VII.F1-7, VII.F2-7, VII.F3-7, VII.F4-6, VII.G-1
Loss of Material	Wear	This material used in HVAC systems is not expected to rub against other components to cause mechanical wear.	TR-8, Section 7.2	VII.F1-5, VII.F1-6, VII.F2-5, VII.F2-6, VII.F3-5, VII.F3-6, VII.F4-4, VII.F4-5

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Non-Metallic (Rubber)
(Rubber, butyl rubbers, fluorelastomers, neoprene, nitrile rubbers, silicone rubber, Viton, ethylene-propylene rubber [EPR]) and ethylene-propylene dienyl monomer [EPDM].

ENVIRONMENT/FLUID: Atmosphere/Weather

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Hardening and Loss of Strength	Elastomer Degradation	Applicable for exposures exceeding 10^6 rads total integrated dose over the period of extended operation. Applicable for temperatures >95°F	EPRI 1002950, Section 7.3.1	VII.G-2

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Non-Metallic (Rubber)
(Rubber, butyl rubbers, fluorelastomers, neoprene, nitrile rubbers, silicone rubber, Viton, ethylene-propylene rubber [EPR]) and ethylene-propylene dienyl monomer [EPDM].

ENVIRONMENT/FLUID: Raw Water

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Hardening and Loss of Strength	Elastomer Degradation	Always.	EPRI 1002950, Section 7.3.1	VII.C1-1
Loss of Material	Erosion	Always.	NUREG-1801, Rev. 1	VII.C1-2

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Non-Metallic (Rubber)
(Rubber, butyl rubbers, fluorelastomers, neoprene, nitrile rubbers, silicone rubber, Viton, ethylene-propylene rubber [EPR]) and ethylene-propylene dienyl monomer [EPDM].

ENVIRONMENT/FLUID: Treated Water

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Hardening and Loss of Strength	Elastomer Degradation	Always.	EPRI 1002950, Section 7.3.1	VII.A3-1

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Stainless Steel
(Includes sensitized and cast austenitic stainless steel)

ENVIRONMENT/FLUID: Air/Gas

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Cracking	Stress Corrosion Cracking	INTERNAL: Gas is not dried air, N2, CO2, H2, or fluorocarbons, component susceptible to wetted environment, a potential for concentrating contaminants exist, and temperature is > 140°F. EXTERNAL: Temperature < 212°F, surface is exposed to aggressive chemical species such as boric acid leakage, temperature > 140°F and component is subject to wetting other than normal environment.	EPRI 1003056, Appendix D, Section 3.2.2 EPRI 1003056, Appendix E, Section 3.2.2	IV.A2-5, IV.A2-6, IV.C2-7, IV.C2-17, VII.H2-1
Cracking	Cyclic Loading	Pressurizer Integral Support: Air with metal temperature up to 288°C (550°F)	WCAP-14574-A, Section 3.1	IV.C2-16
Heat Transfer Degradation	Fouling	Applicable for heat exchanger tubes when potential for accumulation of deposits (sediment, silt, dust, corrosion products, etc.) exists.	EPRI 1003056, Appendix G, Table 6-7	None
Loss of Material	Crevice Corrosion	INTERNAL: Replacement gas for fluorocarbons used, replacement gas is corrosive or gas is not dried air, N2, CO2, H2, or fluorocarbons, component susceptible to wetted environment and a potential for concentrating contaminants exists. EXTERNAL: Temperature < 212°F, surface is exposed to aggressive chemical species and component is subject to wetting other than normal environment.	EPRI 1003056, Appendix D, Section 3.1.3 EPRI 1003056, Appendix E, Section 3.1.3	V.A-26, V.D1-29, VII.D-4, VII.F1-1, VII.F2-1, VII.F3-1, VII.H2-2
Loss of Material	Fretting	Applicable for the exterior of heat exchanger tubes.	EPRI 1003056, Appendix G, Table 6-7	None
Loss of Material	Microbiologically Influenced Corrosion	INTERNAL: Gas is not dried air, N2, CO2, H2, or fluorocarbons, component susceptible to wetted environment and potential source of MIC. EXTERNAL: Temperature < 212°F, surface is exposed to aggressive chemical species and component is subject to wetting other than normal environment.	EPRI 1003056, Appendix D, Section 3.1.6 EPRI 1003056, Appendix E, Section 3.1.6	None

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Stainless Steel
(Includes sensitized and cast austenitic stainless steel)

ENVIRONMENT/FLUID: Air/Gas (Continued)

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Loss of Material	Pitting Corrosion	INTERNAL: Replacement gas for fluorocarbons used, replacement gas is corrosive or gas is not dried air, N2, CO2, H2, or fluorocarbons, component susceptible to wetted environment and a potential for concentrating contaminants exists. EXTERNAL: Temperature < 212°F, surface is exposed to aggressive chemical species and component is subject to wetting other than normal environment.	EPRI 1003056, Appendix D, Section 3.1.4 EPRI 1003056, Appendix E, Section 3.1.4	V.A-26, V.D1-29, VII.D-4, VII.F1-1, VII.F2-1, VII.F3-1, VII.H2-2
Loss of Material	Wear	Relative motion between surfaces (External)	EPRI 1003056, Appendix E, Section 3.1.7.	IV.A2-7
Reduction in Fracture Toughness	Radiation Embrittlement	Fluence $>10^{17}$ neutrons/cm^2. Applicable only for components inside the primary shield wall.	EPRI 1003056, Appendix D, Section 3.3.2	None
Stress Relaxation	Loss of Preload	Applicable for bolted closures.	EPRI 1003056, Appendix F, Section 3.1	IV.A2-8, IV.C2-8
Cracking	Fatigue	Fatigue will be addressed in a TLAA evaluation.	Refer to TLAA.	None

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Stainless Steel
(Includes sensitized and cast austenitic stainless steel)

ENVIRONMENT/FLUID: Atmosphere/Weather

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Cracking	Stress Corrosion Cracking	Temperature < 212°F, surface is exposed to aggressive chemical species, temperature > 140 F and component is buried or subject to wetting other than normal environment.	EPRI 1003056, Appendix E, Section 3.2.2	None
Loss of Material	Crevice Corrosion	Temperature < 212°F, surface is exposed to aggressive chemical species and component is buried or subject to wetting other than normal environment.	EPRI 1003056, Appendix E, Section 3.1.3	None
Loss of Material	Microbiologically Influenced Corrosion	Temperature < 212°F, surface is exposed to aggressive chemical species and component is buried or subject to wetting other than normal environment.	EPRI 1003056, Appendix E, Section 3.1.6	None
Loss of Material	Pitting Corrosion	Temperature < 212°F, surface is exposed to aggressive chemical species and component is buried or subject to wetting other than normal environment.	EPRI 1003056, Appendix E, Section 3.1.4	None
Loss of Material	Wear	Relative motion between surfaces (External)	EPRI 1003056, Appendix E, Section 3.1.7.	None

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Stainless Steel
(Includes sensitized and cast austenitic stainless steel)

ENVIRONMENT/FLUID: Oil

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Cracking	Stress Corrosion Cracking/IGA	Fuel Oil Only: Potential for water pooling / separation, 02 > 100 ppb and temperature > 140°F.	EPRI 1003056, Appendix C, Section 3.2.2	None
Reduction of Heat Transfer	Fouling	Applicable for heat exchanger tubes when potential for accumulation of deposits (sediment, silt, dust, corrosion products, micro- or macro-organisms, etc.) exists. (1)	EPRI 1003056, Appendix G, Table 6-6	V.A-14, V.D1-10, VIII.G-12
Loss of Material	Crevice Corrosion	Presence of water contamination (Lube Oil Only) and potential for water pooling / separation.	EPRI 1003056, Appendix C, Section 3.1.3	V.D1-24, VII.C1-14, VII.C2-12, VII.E1-15, VII.G-17, VII.G-18, VII.H1-6, VII.H2-16, VII.H2-17, VIII.A-9, VIII.D1-3, VIII.E-26, VIII.G-3, VIII.G-29
Loss of Material	Fretting	Applicable for the exterior of heat exchanger tubes.	EPRI 1003056, Appendix G, Table 6-6	None
Loss of Material	Microbiologically Influenced Corrosion	Fuel Oil: Always a concern. Lubricating Oil: To be evaluated based on plant specific operating experience relative to presence of water contamination and potential for water pooling / separation.	EPRI 1003056, Appendix C, Section 3.1.6	VII.C1-14, VII.C2-12, VII.E1-15, VII.G-17, VII.G-18, VII.H1-6, VII.H2-16, VII.H2-17, VIII.A-9, VIII.D1-3, VIII.E-26, VIII.G-3, VIII.G-29
Loss of Material	Pitting Corrosion	Presence of water contamination (Lube Oil Only) and potential for water pooling / separation.	EPRI 1003056, Appendix C, Section 3.1.4	V.D1-24, VII.C1-14, VII.C2-12, VII.E1-15, VII.G-17, VII.G-18, VII.H1-6, VII.H2-16, VII.H2-17, VIII.A-9, VIII.D1-3, VIII.E-26, VIII.G-3, VIII.G-29

(1) The Aging Management Guideline (AMG) bases aging effects identification on strict controls for the quality and purity of the lubricating oil and the fact that they are regularly checked. The AMG assumes that very little corrosion occurs in lubricating oil systems because oxygen content is low, oils are not good electrolytes and purification systems are generally installed and/or corrosion inhibitors added to maintain the oil free of corrosion products.

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Stainless Steel
(Includes sensitized and cast austenitic stainless steel)

ENVIRONMENT/FLUID: Raw Water

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Cracking	Stress Corrosion Cracking/IGA	Temperature > 140°F.	EPRI 1003056, Appendix B, Section 3.2.2	None
Heat Transfer Degradation	Fouling	Applicable for heat exchanger tubes when potential for accumulation of deposits (sediment, silt, dust, corrosion products, micro- or macro-organisms, etc.) exists.	EPRI 1003056, Appendix G, Table 6-5	V.A-15, V.D1-11, VII.C1-7, VII.C3-1, VII.G-7, VII.H2-6, VIII.E-12, VIII.F-9, VIII.G-13
Loss of Material	Fouling	Subject to accumulation of deposits (sediment, silt, dust, corrosion products, micro- or macro-organisms, etc.)	TBD	V.A-8, V.C-3, V.D1-5, VII.C1-15, VII.G-19, VIII.E-3, VIII.F-2, VIII.G-4
Loss of Material	Crevice Corrosion	Always.	EPRI 1003056, Appendix B, Section 3.1.4	V.A-8, V.C-3, V.D1-5, V.D1-15, V.D1-25, VII.A2-1, VII.A3-8, VII.C1-15, VII.C3-7, VII.E1-17, VII.G-19, VII.H2-18, VIII.E-3, VIII.E-27, VIII.F-2, VIII.F-22, VIII.G-4, VIII.G-30
Loss of Material	Erosion	Component subject to high velocities, constricted flow, or fluid change of direction.	EPRI 1003056, Appendix B, Section 3.1.6	None
Loss of Material	Fretting	Applicable for the exterior of heat exchanger tubes.	EPRI 1003056, Appendix G, Table 6-5	None
Loss of Material	Microbiologically Influenced Corrosion	pH < 10.	EPRI 1003056, Appendix B, Section 3.1.7	V.A-8, V.C-3, V.D1-5, V.D1-25, VII.H2-18, VIII.E-3, VIII.E-27, VIII.F-2, VIII.F-22, VIII.G-4, VIII.G-30
Loss of Material	Pitting Corrosion	Low Flow (< 3fps)	EPRI 1003056, Appendix B, Section 3.1.5	V.A-8, V.C-3, V.D1-5, V.D1-15, V.D1-25, VII.A2-1, VII.A3-8, VII.C1-15, VII.C3-7, VII.E1-17, VII.G-19, VII.H2-18, VIII.E-3, VIII.E-27, VIII.F-2, VIII.F-22, VIII.G-4, VIII.G-30

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Stainless Steel
(Includes sensitized and cast austenitic stainless steel)

ENVIRONMENT/FLUID: Soil

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Loss of Material	Crevice Corrosion	Always when exposed to ground water.	EPRI 1003056, Appendix E, Table 4-1	V.D1-26, VII.C1-16, VII.C3-8, VII.G-20, VII.H1-7, VII.H2-19, VIII.E-28, VIII.G-31
Loss of Material	Pitting Corrosion	Always when exposed to ground water with low flow (< 3fps).	EPRI 1003056, Appendix E, Table 4-1	V.D1-26, VII.C1-16, VII.C3-8, VII.G-20, VII.H1-7, VII.H2-19, VIII.E-28, VIII.G-31

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Stainless Steel
(Includes sensitized and cast austenitic stainless steel)

ENVIRONMENT/FLUID: Treated Water and/or Steam

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Change in Dimension	Void Swelling	Applicable only for reactor vessel internals.	WCAP-14577, Section 3.1.11	IV.B2-1, IV.B2-3, IV.B2-4, IV.B2-6, IV.B2-7, IV.B2-9, IV.B2-11, IV.B2-15, IV.B2-17, IV.B2-18, IV.B2-19, IV.B2-22, IV.B2-23, IV.B2-27, IV.B2-29, IV.B2-35, IV.B2-39, IV.B2-41, IV.B3-4, IV.B3-8, IV.B3-10, IV.B3-12, IV.B3-13, IV.B3-14, IV.B3-16, IV.B3-19, IV.B3-20, IV.B3-27, IV.B4-1, IV.B4-3, IV.B4-8, IV.B4-11, IV.B4-12, IV.B4-16, IV.B4-17, IV.B4-23, IV.B4-24, IV.B4-30, IV.B4-31, IV.B4-35, IV.B4-39, IV.B4-41, IV.B4-45, IV.B4-46
Cracking	Stress Corrosion Cracking/IGA	02 > 100 ppb or corrosive environment and temperature > 140 F.	EPRI 1003056, Appendix A, Section 3.2.2	IV.A2-1, IV.A2-5, IV.A2-11, IV.A2-15, IV.B2-2, IV.B2-8, IV.B2-10, IV.B2-12, IV.B2-16, IV.B2-20, IV.B2-24, IV.B2-28, IV.B2-30, IV.B2-36, IV.B2-40, IV.B2-42, IV.B3-2, IV.B3-5, IV.B3-9, IV.B3-11, IV.B3-15, IV.B3-21, IV.B3-23, IV.B3-28, IV.B4-2, IV.B4-5, IV.B4-7, IV.B4-10, IV.B4-13, IV.B4-18, IV.B4-20, IV.B4-22, IV.B4-25, IV.B4-29, IV.B4-32, IV.B4-34, IV.B4-36, IV.B4-40, IV.B4-43, IV.B4-44, IV.C2-1, IV.C2-2, IV.C2-3, IV.C2-5, IV.C2-17, IV.C2-19, IV.C2-20, IV.C2-22, IV.C2-27, IV.D1-1, IV.D1-7, IV.D1-14, V.A-24, V.A-28, V.C-8, V.D1-23, V.D1-31, V.D1-33, VII.A2-7, VII.A3-10, VII.C2-11, VII.E1-5, VII.E1-7, VII.E1-9, VII.E1-20,

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Stainless Steel
(Includes sensitized and cast austenitic stainless steel)

ENVIRONMENT/FLUID: Treated Water and/or Steam (Continued)

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Cracking (Continued)	Stress Corrosion Cracking/IGA (Continued)	02 > 100 ppb or corrosive environment and temperature > 140 F. (Continued)	EPRI 1003056, Appendix A, Section 3.2.2 (Continued)	VIII.A-10, VIII.B1-2, VIII.B1-5, VIII.C-2, VIII.D1-5, VIII.E-25, VIII.E-30, VIII.E-38, VIII.F-3, VIII.F-21, VIII.F-24, VIII.G-28, VIII.G-33
Heat Transfer Degradation	Fouling	Applicable for heat exchanger tubes when potential for accumulation of deposits (sediment, silt, dust, corrosion products, micro- or macro-organisms, etc.) exists.	EPRI 1003056, Appendix G, Table 6-3	V.A-13, V.A-16, V.D1-9, VII.C2-3, VIII.E-11, VIII.E-13, VIII.F-8, VIII.F-10, VIII.G-11
Loss of Material	Crevice Corrosion	O2 >100 ppb.	EPRI 1003056, Appendix A, Section 3.1.4	IV.A2-14, IV.B2-32, IV.B3-25, IV.B4-38, IV.C2-15, IV.D1-15, V.A-7, V.A-23, V.A-27, V.C-4, V.C-7, V.D1-4, V.D1-22, V.D1-30, VII.A2-1, VII.A3-8, VII.C2-10, VII.E1-17, VII.H2-2, VIII.A-12, VIII.B1-3, VIII.B1-4, VIII.C-1, VIII.D1-4, VIII.E-2, VIII.E-4, VIII.E-24, VIII.E-29, VIII.E-36, VIII.E-40, VIII.F-1, VIII.F-20, VIII.F-23, VIII.F-27, VIII.G-2, VIII.G-27, VIII.G-32, VIII.G-41
Loss of Material	Erosion	Material is subject to high velocity, constricted flow, or fluid direction change and fluid contains particulates (single phase) or water droplets (two phase flow).	EPRI 1003056, Appendix A, Section 3.1.6	V.D1-14
Loss of Material	Fretting	Applicable for the exterior of heat exchanger tubes and the reactor vessel internals.	EPRI 1003056, Appendix G, Table 6-3	IV.D1-15
Loss of Material	Microbiologically Influenced Corrosion	Potential for MIC contamination and temperatures <210°F and Ph <10.	EPRI 1003056, Appendix A, Section 3.1.7	None

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Stainless Steel
(Includes sensitized and cast austenitic stainless steel)

ENVIRONMENT/FLUID: Treated Water and/or Steam (Continued)

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Loss of Material	Pitting Corrosion	O2>100ppb, corrosive environment and low flow (<3 fps).	EPRI 1003056, Appendix A, Section 3.1.5	IV.A2-14, IV.B2-32, IV.B3-25, IV.B4-38, IV.C2-15, V.A-7, V.A-23, V.A-27, V.C-4, V.C-7, V.D1-4, V.D1-22, V.D1-30, VII.A2-1, VII.A3-8, VII.C2-10, VII.E1-17, VII.H2-2, VIII.A-12, VIII.B1-3, VIII.B1-4, VIII.C-1, VIII.D1-4, VIII.E-2, VIII.E-4, VIII.E-24, VIII.E-29, VIII.E-36, VIII.E-40, VIII.F-1, VIII.F-20, VIII.F-23, VIII.F-27, VIII.G-2, VIII.G-27, VIII.G-32, VIII.G-41
Reduction of Fracture Toughness	Thermal Embrittlement	Applicable to CASS >482°F	EPRI 1003056, Appendix A, Section 3.3.1	IV.A2-10, IV.C2-4, IV.C2-6, V.D1-16
Reduction of Fracture Toughness	Radiation Embrittlement	Fluence >1017 neutrons/cm2. Applicable only for components inside the primary shield wall.	EPRI 1003056, Appendix A, Section 3.3.2	IV.A2-16, IV.A2-17, IV.A2-23, IV.A2-24, IV.B2-3, IV.B2-6, IV.B2-9, IV.B2-17, IV.B2-18, IV.B2-22, IV.B3-10, IV.B3-12, IV.B3-16, IV.B3-20, IV.B4-1, IV.B4-12, IV.B4-16, IV.B4-24, IV.B4-31, IV.B4-41, IV.B4-46
Reduction of Fracture Toughness	Combined Thermal and Radiation Embrittlement	Applicable only for reactor vessel internals.	WCAP-14577. Sections 3.1.1 and 3.1.8	IV.B2-21, IV.B2-37, IV.B3-1, IV.B3-18, IV.B4-4, IV.B4-21, IV.B4-28
Loss of Preload	Stress Relaxation	Applicable only for reactor vessel internals.	WCAP-14577, Section 3.1.6	IV.B2-5, IV.B2-14, IV.B2-25, IV.B2-33, IV.B2-38, IV.B3-6, IV.B3-7, IV.B4-6, IV.B4-9, IV.B4-14, IV.B4-19, IV.B4-26, IV.B4-33,
Loss of Material	Wear	Relative motion between surfaces. Applicable only for reactor vessel internals.	WCAP-14577, Section 3.1.7	IV.B2-13, IV.B2-26, IV.B2-34, IV.B3-3, IV.B3-17, IV.B3-22, IV.B3-26, IV.B4-15, IV.B4-27, IV.B4-42

Attachment D
Metallic and Elastomer Aging Effects

MATERIAL: Stainless Steel
(Includes sensitized and cast austenitic stainless steel)

ENVIRONMENT/FLUID: Treated Water and/or Steam (Continued)

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Cumulative Fatigue Damage	Fatigue	Fatigue to be addressed in a TLAA evaluation.	Refer to TLAA.	IV.A2-21, IV.B2-31, IV.B3-24, IV.B4-37, IV.C2-10, IV.C2-23, IV.C2-25, IV.D1-8, V.D1-27, VII.E1-4, VII.E1-16
Cracking	Thermal and Mechanical Loading / Cyclic Loading	Applicable for the RCS and lines connected to the RCS and the pressurizer if clad with stainless steel.	WCAP-14575-A, Section 3.2.1	IV.A2-22, IV.C2-1, IV.C2-18, IV.C2-26, VII.E1-5, VII.E1-7, VII.E1-9
Loss of Material	Cladding Breach	Applicable for pump casings exposed to an internal environment of treated borated water, if clad with stainless steel.	NRC Information Notice 94-63, "Boric Acid Corrosion of Charging Pump Casings Caused by Cladding Cracks."	V.D1-32, VII.E1-21

Attachment E
Concrete & Miscellaneous Structural Materials Aging Effects

MATERIAL: Concrete

ENVIRONMENT/FLUID: Air

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Cracking	Dry Shrinkage	Applicable for masonry block walls.	EPRI 1002950, Section 5.3.4	III.A1-11, III.A2-11, III.A3-11, III.A5-11, III.A6-10
Change of Material Properties	Elevated Temperatures	Temperatures > 150°F (General Area) or Temperatures > 200°F (Local Area)	EPRI 1002950, Section 5.3.3.3	III.A1-1, III.A3-1, III.A4-1, III.A5-1
Loss of Material	Elevated Temperatures	Temperatures > 150°F (General Area) or Temperatures > 200°F (Local Area)	EPRI 1002950, Section 5.3.1.3	None
Cracking	Elevated Temperatures	Temperatures > 150°F (General Area) or Temperatures > 200°F (Local Area)	EPRI 1002950, Section 5.3.2.5	None
Cracking	Expansion and Contraction	Applicable for masonry block walls.	EPRI 1002950, Section 5.3.4	III.A1-11, III.A2-11, III.A3-11, III.A5-11, III.A6-10
Cracking	Irradiation	Neutron fluence level experienced by concrete during the LR term > 1 x 10^{19} neutrons/cm^2 (neutron energy > 1 MeV) or Maximum integrated gamma dose experienced by concrete during the LR term > 1 x 10^{10} rads.	EPRI 1002950, Section 5.3.2.6	None
Change of Material Properties	Irradiation	Neutron fluence level experienced by concrete during the LR term > 1 x 10^{19} neutrons/cm^2 (neutron energy > 1 MeV) or Maximum integrated gamma dose experienced by concrete during the LR term > 1 x 10^{10} rads.	EPRI 1002950, Section 5.3.3.4	None
Cracking	Joint Isolation and Durability	Applicable for masonry block walls.	EPRI 1002950, Section 5.3.4	III.A1-11, III.A2-11, III.A3-11, III.A5-11, III.A6-10

Attachment E
Concrete and Miscellaneous Structural Materials Aging Effects

MATERIAL: Concrete

ENVIRONMENT/FLUID: Atmosphere/Weather

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Cracking	Dry Shrinkage	Applicable for masonry block walls.	EPRI 1002950, Section 5.3.4	III.A1-11, III.A2-11, III.A3-11, III.A5-11, III.A6-10
Change of Material Properties	Aggressive Chemical Attack	pH <5.5, chloride >500 ppm, or sulfates >1500 ppm.	EPRI 1002950, Section 5.3.3.2	II.A1-4, III.A1-10, III.A3-10, III.A5-10, III.A7-9125
Loss of Material	Aggressive Chemical Attack	pH <5.5, chloride >500 ppm, or sulfates >1500 ppm.	EPRI 1002950, Section 5.3.1.4	II.A1-4, III.A1-10, III.A3-10, III.A5-10, III.A7-9, VII.G-30
Cracking	Expansion and Contraction	Applicable for masonry block walls.	EPRI 1002950, Section 5.3.4	III.A1-11, III.A2-11, III.A3-11, III.A5-11, III.A6-10
Cracking	Freeze-Thaw	Concern when the design of concrete mix does not meet the requirements of ACI 318-63 and ACI 301-66 (or later versions of these codes), and exposed to outside weather.	EPRI 1002950, Section 5.3.2.1	II.A1-2, III.A1-6, III.A3-6, III.A5-6, III.A6-5, III.A7-5, III.A8-5, VII.G-30
Loss of Material	Freeze-Thaw	Concern when the design of concrete mix does not meet the requirements of ACI 318-63 or ACI 301-66 (or later versions of these codes), and exposed to outside weather.	EPRI 1002950, Section 5.3.1.1	II.A1-2, III.A1-6, III.A3-6, III.A5-6, III.A6-5, III.A7-5, III.A8-5, VII.G-30
Cracking	Joint Isolation and Durability	Applicable for masonry block walls.	EPRI 1002950, Section 5.3.4	III.A1-11, III.A2-11, III.A3-11, III.A5-11, III.A6-10
Change of Material Properties	Leaching of Calcium Hydroxide	Structures that are exposed to flowing liquid, ponding, or hydraulic pressure and defects in the concrete such as cracks, voids, or low strength are necessary to permit movement of water through the concrete.	EPRI 1002950, Section 5.3.3.1	None

Attachment E
Concrete and Miscellaneous Structural Materials Aging Effects

MATERIAL: Concrete

ENVIRONMENT/FLUID: Below Grade

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Loss of Material	Abrasion or Cavitation	Continuously exposed to flowing water containing abrasives	EPRI 1002950, Section 5.3.1.2	III.A6-7
Loss of Material	Aggressive Chemical Attack	pH <5.5, chloride >500 ppm, or sulfates >1500 ppm.	EPRI 1002950, Section 5.3.1.4	II.A1-4, III.A1-5, III.A3-5, III.A5-5, III.A6-3, III.A7-4, III.A8-4
Change of Material Properties	Aggressive Chemical Attack	pH <5.5, chloride >500 ppm, or sulfates >1500 ppm.	EPRI 1002950, Section 5.3.3.2	II.A1-4, III.A1-5, III.A3-5, III.A5-5, III.A6-3, III.A7-4, III.A8-4
Change of Material Properties	Leaching of Calcium Hydroxide	Structures that are exposed to flowing liquid, ponding, or hydraulic pressure and defects in the concrete such as cracks, voids, or low strength are necessary to permit movement of water through the concrete.	EPRI 1002950, Section 5.3.3.1	II.A1-6, III.A1-7, III.A3-7, III.A5-7, III.A6-6, III.A7-6, III.A8-6
Cracking	Settlement	Structures founded on soft soil and/or significant changes in underground water conditions over a long period of time.	EPRI 1002950, Section 5.3.2.4	II.A1-5, III.A1-3, III.A3-3, III.A5-3, III.A6-4, III.A7-2, III.A8-2

Attachment E
Concrete and Miscellaneous Structural Materials Aging Effects

MATERIAL: Concrete

ENVIRONMENT/FLUID: Raw Water

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Loss of Material	Abrasion or Cavitation	Continuously exposed to flowing water containing abrasives or open channel water velocities > 40 fps or closed conduit water velocities > 25fps.	EPRI 1002950, Section 5.3.1.2	III.A6-7
Loss of Material	Aggressive Chemical Attack	pH <5.5, chloride >500 ppm, or sulfates >1500 ppm.	EPRI 1002950, Section 5.3.1.4	II.A1-4, III.A1-5, III.A3-5, III.A5-5, III.A6-3, III.A7-4, III.A8-4
Change of Material Properties	Aggressive Chemical Attack	pH <5.5, chloride >500 ppm, or sulfates >1500 ppm.	EPRI 1002950, Section 5.3.3.2	II.A1-4, III.A1-5, III.A3-5, III.A5-5, III.A6-3, III.A7-4, III.A8-4
Cracking	Freeze-Thaw	Concern when the design of concrete mix does not meet the requirements of ACI 318-63 and ACI 301-66 (or later versions of these codes), and exposed to outside weather.	EPRI 1002950, Section 5.3.2.1	II.A1-2, III.A1-6, III.A3-6, III.A5-6, III.A6-5, III.A7-5, III.A8-5, VII.G-30
Loss of Material	Freeze-Thaw	Concern when the design of concrete mix does not meet the requirements of ACI 318-63 or ACI 301-66 (or later versions of these codes), and exposed to outside weather.	EPRI 1002950, Section 5.3.1.1	II.A1-2, III.A1-6, III.A3-6, III.A5-6, III.A6-5, III.A7-5, III.A8-5, VII.G-30
Change of Material Properties	Leaching of Calcium Hydroxide	Structures that are exposed to flowing liquid, ponding, or hydraulic pressure and defects in the concrete such as cracks, voids, or low strength are necessary to permit movement of water through the concrete.	EPRI 1002950, Section 5.3.3.1	II.A1-6, III.A1-7, III.A3-7, III.A5-7, III.A6-6, III.A7-6, III.A8-6

Attachment E
Concrete and Miscellaneous Structural Materials Aging Effects

MATERIAL: Non-Metallic (Fire Stops)
(Fire stops [e.g. Maranite]; Fire-retardant coatings [e.g. Pyrocrete]; Gypsum)

ENVIRONMENT/FLUID: Air/Gas

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Loss of Material	Abrasion	In vicinities where there are interactions with other vibrating components.	EPRI 1002950, Section 6.3.1	None
Change of Material Properties	Irradiation	Applicable for exposures exceeding 10^6 Rads total integrated dose over the period of extended operation.	EPRI 1002950, Section 6.3.3	None
Cracking	Vibration	In vicinities where there are interactions with other vibrating components.	EPRI 1002950, Section 6.3.2.1	None.

Attachment E
Concrete and Miscellaneous Structural Materials Aging Effects

MATERIAL: Non-Metallic (Fire Wraps)
(Fire wraps: mineral-wool batts, Thermo-lag, and mono-coats)

ENVIRONMENT/FLUID: Air/Gas

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Loss of Material	Abrasion	In vicinities where there are interactions with other vibrating components.	EPRI 1002950, Section 6.3.1	None
Loss of Material	Flaking	Material may be free over time owing to the force of gravity, airflow in the vicinity of the fireproofing, and vibrations induced into the fireproofed members.	EPRI 1002950, Section 6.3.1	None
Change of Material Properties	Irradiation	Applicable for exposures exceeding 10^6 Rads total integrated dose over the period of extended operation	EPRI 1002950, Section 6.3.3	None
Cracking	Vibration	In vicinities where there are interactions with other vibrating components.	EPRI 1002950, Section 6.3.1	None

Attachment E
Concrete and Miscellaneous Structural Materials Aging Effects

MATERIAL: Non-Metallic (Fire Stop Sealants)
(Silicone foam, elastomeric seals)

ENVIRONMENT/FLUID: Air/Gas

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Increased hardness, shrinkage and loss of strength	Weathering	Elastomeric fire barrier seals exposed to weather or plant indoor air.	N / A	VII.G-1, VII.G-2

Attachment E
Concrete and Miscellaneous Structural Materials Aging Effects

MATERIAL: Non-Metallic (Fiberglass)

ENVIRONMENT/FLUID: Atmosphere/Weather

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Reduction of Strength and Cracking	Ultraviolet Exposure	Roofing Panels exposed to Atmosphere/Weather	PG&E Letter LRFS-10-007	None

Attachment F
Electrical Aging Effects

MATERIAL: Non-Metallic (Electrical Rubber)
[CSPE (Hypalon), EPDM, EPR, EFTE (Tefzel), Neoprene, PVC, Silicone rubber, Viton, XLPE/XLPO, Polymide (Kapton), Noryl, Glastic, Nylon, Phenolic, Epoxy resins, RTV silicone rubber, Kevlar, Polysulfone, Melamine]

ENVIRONMENT/FLUID: Air/Gas

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Embrittlement	Irradiation	60-year equivalent TID, greater than or equal to, the applicable value in Table 4-7 of SANDIA96-0344 (gamma / neutron material-specific dose). Or adverse environment	SANDIA96-0344 Table 4.7 [Radiation Aging]. IEEE P1205, Table A2-1. WCAP-14764, Table 3-4.	VI.A-2 VI.A-3
Cracking	Irradiation	60-year equivalent TID, greater than or equal to, the applicable value in Table 4-7 of SANDIA96-0344 (gamma / neutron material-specific dose). Or adverse environment	SANDIA96-0344 Table 4.7 [Radiation Aging]. IEEE P1205, Table A2-1. WCAP-14764, Table 3-4.	VI.A-2 VI.A-3
Embrittlement	Thermal Exposure	Ambient temperature to which instrumentation cable insulation is exposed exceeds the 60-year service temperature limit for the insulating material. For medium and low voltage power cables ambient temperature plus temperature rise across insulation due to ohmic heating exceed the 60-year service temperature limit. Bulk ambient plus ohmic heating effects and local heating source exceed 60-year limit. Or adverse localized environment	SANDIA96-0344 Table 4.1 [Thermal Aging]; IEEE P1205, Guide for Assessing, Monitoring, and Mitigating Aging Effects on Class 1E Equipment Used in Nuclear Generating Stations, Table A2-1; WCAP-14764 Aging Management Evaluation for Cable, Connectors, and Buswork, Table 3-4.	VI.A-2 VI.A-3
Cracking	Thermal Exposure	Ambient temperature to which instrumentation cable insulation is exposed exceeds the 60-year service temperature limit for the insulating material. For medium and low voltage power cables ambient temperature plus temperature rise across insulation due to ohmic heating exceed the 60-year service temperature limit. Bulk ambient plus ohmic heating effects and local heating source exceed 60-year limit. Or adverse localized environment	SANDIA96-0344 Table 4.1 [Thermal Aging]; IEEE P1205, Guide for Assessing, Monitoring, and Mitigating Aging Effects on Class 1E Equipment Used in Nuclear Generating Stations, Table A2-1; WCAP-14764 Aging Management Evaluation for Cable, Connectors, and Buswork, Table 3-4.	VI.A-2 VI.A-3

Attachment F
Electrical Aging Effects

MATERIAL: Non-Metallic (Electrical Rubber)
[CSPE (Hypalon), EPDM, EPR, EFTE (Tefzel), Neoprene, PVC, Silicone rubber, Viton, XLPE/XLPO, Polymide (Kapton), Noryl, Glastic, Nylon, Phenolic, Epoxy resins, RTV silicone rubber, Kevlar, Polysulfone, Melamine]

ENVIRONMENT/FLUID: Raw Water

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Breakdown of Insulation	Water Treeing	Medium voltage or higher cables energized more than 25% of the time. Applicable for cable subject to wetting, installed in ducts, installed in trenches, or direct buried.	SANDIA 96-0344 Section 4.1.5 [Electrical Aging];	VI.A-4

Attachment F
Electrical Aging Effects

MATERIAL: Non-Metallic
(Mineral insulation, aluminum-oxide, magnesium-oxide)

ENVIRONMENT/FLUID: Air/Gas

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Reduced Strength	Ozone Exposure	Exposure to high levels of ozone that might be associated with high-voltage electrical equipment.	Engineered Materials Handbook, Volume 1, Composites, ASM Handbook Committee	VI.A-3
Reduced Strength	Ultraviolet Exposure	Exposure to direct sun light.	Engineered Materials Handbook, Volume 2, Engineering Plastics, ASM Handbook Committee	VI.A-3

Attachment F
Electrical Aging Effects

MATERIAL: Non-Metallic (Fiberglass, PVC)

ENVIRONMENT/FLUID: Air/Gas

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Reduced Strength	Ozone Exposure	Exposure to high levels of ozone that might be associated with high-voltage electrical equipment.	Engineered Materials Handbook, Volume 1, Composites, ASM Handbook Committee	VI.A-3
Reduced Strength	Ultraviolet Exposure	Exposure to direct sun light.	Engineered Materials Handbook, Volume 2, Engineering Plastics, ASM Handbook Committee	VI.A-3

Attachment F
Electrical Aging Effects

MATERIAL: Non-Metallic (Fiberglass, PVC)

ENVIRONMENT/FLUID: Atmosphere/Weather

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Reduced Strength	Ozone Exposure	60-year equivalent TID, greater than or equal to, the applicable value in Table 4-7 of SANDIA96-0344 (gamma / neutron material-specific dose).	Engineered Materials Handbook, Volume 1, Composites, ASM Handbook Committee	VI.A-3
Reduced Strength	Ultraviolet Exposure	Exposure to direct sun light.	Engineered Materials Handbook, Volume 2, Engineering Plastics, ASM Handbook Committee	VI.A-3

Attachment F
Electrical Aging Effects

MATERIAL: Non-Metallic (Insulation material – bakelite, phenolic melamine or ceramic, molded polycarbonate and other)

ENVIRONMENT/FLUID: Air/Gas

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Embrittlement	Cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced insulation resistance (IR); electrical failure/ degradation (Thermal/ thermoxidative) of organics/thermoplastics, radiation-induced oxidation, moisture intrusion and ohmic heating	Ambient temperature to which insulating material is exposed exceeds the 60-year service temperature limit for the insulating material. Or exposed to adverse localized environment.	SANDIA96-0344 Table 4.1 [Thermal Aging]; IEEE P1205, Guide for Assessing, Monitoring, and Mitigating Aging Effects on Class 1E Equipment Used in Nuclear Generating Stations, Table A2-1	VI.A-6
None	None	Exposed to plant in-door air uncontrolled	SANDIA96-0344 Table 4.1 [Thermal Aging]; IEEE P1205, Guide for Assessing, Monitoring, and Mitigating Aging Effects on Class 1E Equipment Used in Nuclear Generating Stations, Table A2-1	VI.A-7

Attachment F
Electrical Aging Effects

MATERIAL: Copper Alloy (Various metals used for electrical connections)

ENVIRONMENT/FLUID: Air/Gas/Vibration

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Loosening of bolted	Vibration, chemical contamination, corrosion, and oxidation	Exposed to chemical contamination or high vibration	EPRI TR-003057, Electrical Final Handbook	VI.A-1
Corrosion of connector contact surfaces	Intrusion of borated water	Exposed to borated water	EPRI TR-003057, Electrical Final Handbook	VI.A-5
Fatigue	Frequent manipulation, vibration, chemical contamination, corrosion, and oxidation	Fuse subject to frequent manipulation or exposed to chemical contamination.	SANDIA96-0344 Table 4.1 [Thermal Aging]; IEEE P1205, Guide for Assessing, Monitoring, and Mitigating Aging Effects on Class 1E Equipment Used in Nuclear Generating Stations, Table A2-1	VI.A-8

Attachment F
Electrical Aging Effects

MATERIAL: Porcelain (High Voltage Insulators)

ENVIRONMENT/FLUID: Atmosphere/Weather

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Degradation of insulator quality	Presence of any salt deposits or surface contamination	Exposed to outdoor environment subject to industry air pollution or salt spray.	EPRI TR-003057, Electrical Final Handbook	VI.A-9
Loss of material	Mechanical wear due to wind blowing on transmission conductors	Exposed to outdoor environment subject to industry air pollution or salt spray. Expose to significant swing.	EPRI TR-003057, Electrical Final Handbook	VI.A-10

Attachment F
Electrical Aging Effects

MATERIAL: Malleable iron, aluminum, galvanized steel, cement (High Voltage Insulators)

ENVIRONMENT/FLUID: Atmosphere/Weather

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Degradation of insulator quality	Presence of any salt deposits or surface contamination	Exposed to outdoor environment subject to industry air pollution or salt spray.	EPRI TR-003057, Electrical Final Handbook	VI.A-9
Loss of material	Mechanical wear due to wind blowing on transmission conductors	Exposed to outdoor environment subject to industry air pollution or salt spray. Expose to significant swing. .	EPRI TR-003057, Electrical Final Handbook	VI.A-10

Attachment F
Electrical Aging Effects

MATERIAL: Aluminum, copper, bronze, stainless steel, galvanized steel (Switchyard Bus and Connections)

ENVIRONMENT/FLUID: Atmosphere/Weather

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Loss of material	Wind induced abrasion and fatigue	Expose to significant swing.	EPRI TR-003057, Electrical Final Handbook	VI.A-15
Loss of conductor strength	Corrosion Increased resistance of connection/ oxidation or loss of pre-load	Exposed to outdoor environment subject to industry air pollution or salt spray.	EPRI TR-003057, Electrical Final Handbook The National Electrical Safety Code	VI.A-15

Attachment F
Electrical Aging Effects

MATERIAL: Aluminum, steel (Aluminum Conductor Steel Reinforced)

ENVIRONMENT/FLUID: Atmosphere/Weather

AGING EFFECT	AGING MECHANISM	APPLICABILITY	REFERENCES	NUREG-1801
Loss of material	Wind induced abrasion and fatigue	Expose to significant swing.	EPRI TR-003057, Electrical Final Handbook The National Electrical Safety Code	VI.A-16
Loss of conductor strength	Corrosion Increased resistance of connection/ oxidation or loss of pre-load	Exposed to outdoor environment subject to industry air pollution or salt spray.	EPRI TR-003057, Electrical Final Handbook The National Electrical Safety Code IEEE Transactions on Power Delivery, Vol.7, No. 2 April 1992, "Aged ACSR Conductors" Part 1 Testing Procedures for Conductors and Line Items, Part II Prediction of Remaining Life by Ontario Hydro, Toronto, Canada	VI.A-16

Desktop Guide DG-6

License Renewal Boundary Drawings

Revision 0

August 01, 2008

License Renewal Boundary Drawings

Approval Page

Rev	Revision Summary	Prepared by:	Approved by:	Date
0	Initial Issue	Al Saunders	Eric Blocher	Aug. 01, 2008

Revision Summary

Revision	Required Changes to Achieve Revision	Date
0	Initial Issue	Aug. 01, 2008

Table of Contents

1.0 Purpose

Boundary drawings are prepared in accordance with PI-1 to identify portions of systems or structures within the scope of license renewal. This desktop guide supplements PI-1 and provides background and directions for preparing license renewal (LR) boundary drawings in support of STARS plant license renewal applications (LRA). This desktop guide provides directions for general boundary drawing considerations, boundary drawing conventions associated with specific components, and system interface conventions.

2.0 References

2.1 PAMCOBP-PI-1, Scoping and Screening of Systems, Structures and Components

2.2 NUREG-1800, Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants

3.0 Responsibilities

3.1. STARS License Renewal Engineer (STARS LR Engineer)

The STARS LR Engineer is responsible for preparing boundary drawings.

3.2. STARS License Renewal Discipline Lead (STARS LR Discipline Lead)

The STARS LR Discipline Lead is responsible for reviewing boundary drawings as part of the Scoping, Screening and AMR package prior to issuing the package.

4.0 Instructions

4.1. Background

4.1.1. LR boundary drawings are prepared by the COB staff to support STARS plant NRC audits and inspections during the LRA approval process. Boundary drawings are provided as a review aid and a simplified means for depicting in-scope and out of scope components on a system basis.

4.1.2. Boundary drawings are prepared primarily for mechanical systems only. Consistent with PI-1, a limited number of structural, electrical/instrumentation and control drawings are prepared.

4.1.3. Section 2.1.3.2.1 of the LRSRP (Reference 2.2) specifically excludes instrumentation, such as pressure transmitters, pressure indicators, and water level indicators from AMR. Instrumentation of this type does not have to have the pressure retaining boundaries identified because 10 CFR 54.21(a)(1)(i) excludes this instrumentation without exception, unlike pumps and valves. Further, instrumentation is sensitive equipment and degradation of its pressure boundary would be easily detectable in surveillance testing.

4.1.4. Mechanical boundary drawings can be a mark-up of an existing mechanical system Piping and Instrumentation Diagram (PID) or Operations Valve Identification Drawing (OVID). PIDs were used at Wolf Creek and Palo Verde. In certain plant specific cases another type of drawing may be used. For instance, OVIDs were used to develop Diablo Canyon boundary drawings. A project work plan typically identifies the type of base drawing to use for boundary drawing development prior to commencement of production work for each STARS plant.

4.1.5. As a general position, boundary drawings for instrument details are not required. In some cases, such as DCPP, instrument details including tubing and fittings and valves were depicted on separate instrument detail OVIDs. Unless there is something that is unique or out of the ordinary regarding the instrument details, a boundary drawing is not required.

4.1.6. Boundary drawings are prepared for each STARS plant operating unit. This policy is necessary to address unit differences that may exist between plant operating units. In some cases this may not be required depending on plant specific factors. The plant specific project plan will identify if a single unit set of boundary drawings will be used.

4.2. General Boundary Drawing Conventions

4.2.1. This procedure supplements the boundary drawing requirements in PI-1 (Reference 2.1).

4.2.2. As a basic rule, mechanical components that are in the scope of LR are highlighted on mechanical boundary drawings. This rule applies whether the piping and components are subject to AMR or not.

4.2.3. Mechanical components that are in the scope of license renewal are highlighted in color consistent with PI-1 conventions. Only piping and component symbols are highlighted on mechanical drawings not the identifying text.

4.2.4. In the case of (a)(3), piping and components in the main flow path from source to end-point is all that is required to be highlighted. Off path branch lines and connections are not in-scope for (a)(3) and should not be highlighted. Some off path branch lines and connections may be in-scope for (a)(2) due to spatial interaction (FM08).

4.2.5. Descriptive notes should be used on boundary drawings to make the highlighting thought process clear to reviewers. These notes can be special note boxes with arrows pointing to the affected area, or as a general note on the drawing sidebar. The purpose of the notes is to provide clarification, guidance, or background information regarding the highlighting process associated with the affected areas.

4.2.6. A Standard Note Drawing should be developed that includes terminal component (a)(2) symbols, system interface flags, plant system designators, general notes as applicable, and other descriptors as determined to be necessary on a plant specific basis.

4.2.7. Terminal component (a)(2) symbols should be used on boundary drawings to depict the termination of structural integrity attached (FS15) and/or spatial interaction (FM08) in accordance with the plant specific Standard Note Drawing. It is not necessary to use terminal component symbols for open ended piping or piping vent and drain lines.

4.2.8. Boundary drawings should have a plant specific title block. Unique License Renewal drawings shall be assigned consistent with PI-1.

4.3. Component Specific Conventions

4.3.1. Containment penetration symbols often appear on mechanical boundary drawings. Containment penetrations are structural components and should not be highlighted on mechanical boundary drawings. Containment penetrations are within the scope of license renewal and are evaluated in the structural reviews as part of the Containment building.

4.3.2. Electrical components, such as motors and solenoid valve operators that appear on mechanical boundary drawings should not be highlighted on mechanical drawings. Electrical and instrument components are evaluated are evaluated as part the electrical

(LRID ELEC) review. Other examples of electrical components within the scope of license renewal that should not be highlighted on mechanical boundary drawings include, but are not limited to, flow transmitters, level transmitters, pressure transmitters, temperature transmitters and depictions of electrical actuation circuitry.

4.3.3. In-line instruments that are part of the system pressure boundary, including but not limited to locally reading flow meters (i.e. rotameters) and local sight gauge glasses, should be assigned to the subject LRID and highlighted together with associated pressure boundary fittings and valves.

4.3.4. Instruments (LRID ELEC) that are not in-line such as locally reading pressure indicators and thermometers should not be highlighted.

4.3.5. Air, hydraulic and hand valve operators (i.e. mechanical reach-rods, chains, hand wheels, etc.) for valves that are in-scope for (a)(1) or (a)(3) should be highlighted in green. Valve operators for valves in-scope for (a)(2) should not be highlighted.

4.3.6. Circled component identifiers and any associated leader-lines should not be highlighted without regard to whether the symbol for the component being identified is highlighted. Three examples include orifices, pressure test connections and thermowells as discussed below:
- Orifices: the symbol for an orifice should be highlighted consistent with its component function but the circle containing the component ID number, for example "FO-5," should not be highlighted.
- Pressure Test Connections: the symbol for the piping stub and cap should be highlighted consistent with its component function but the circle containing the component ID number, for example "PX-5," should not be highlighted.
- Thermowells/Temperature Indicators & Elements: the circle and leader-line for a thermowell, temperature indicator and temperature element, for example "TW-223," should not be highlighted.

4.3.7. Symbols representing pump casings should be highlighted consistent with their component functions [(a)(1), (a)(2) or (a)(3)] but the motor-driver for the pump should not be highlighted as the motor is an electrical component and should be assigned to LRID ELEC. Similarly, fans or fan housings should be highlighted consistent with their component functions; but, the motor-driver for the fan should not be highlighted. However, any external piping associated with the motor lubricating oil and/or cooling water to internal motor air coolers should be highlighted as the piping and components are mechanical components that support the intended function.

4.3.8. Symbols representing filter and strainer bodies should be highlighted, if appropriate, based on component intended function [(a)(1), (a)(2) or (a)(3)]. If the filter element is depicted separately, as is common in HVAC systems, the filter should be highlighted based on component intended function [(a)(1), (a)(2) or (a)(3)].

4.4. System Interface Conventions

4.4.1. In situations where interfacing system piping and components (different LRID) are shown on the system boundary drawing (parent LRID), the boundary drawing interfacing system components that are in-scope should be colored red or green on the parent LRID boundary drawing. A note should be added to the parent drawing pointing to the interfacing piping and components stating they are evaluated in the interfacing LRID (i.e. PVNGS boundary drawing convention). A system flag may be used instead of a note (i.e. DCPP boundary drawing convention). The interfacing LRID boundary drawing and P&ID (or OVID as appropriate) should be listed as a LRDMT reference in the parent System Scoping document and the parent LRID boundary drawing and P&ID (or OVID as appropriate) should be listed as a LRDMT reference in the interfacing System Scoping document.

4.4.2. In situations where the highlighted system piping on the parent drawing extends to the interfacing boundary drawing, the highlighting should continue onto the interfacing system boundary drawing until a terminal component is reached in the interfacing system piping. If this is the case, show the terminal component (a)(2) symbol on the interfacing system boundary drawing. If the FS15 or FM08 function ends before reaching the interfacing system Boundary Drawing then show the terminal component (a)(2) symbol on the parent system LR Boundary Drawing.

4.4.3. In some cases (such as WCGS), PIDs may be entirely system based (i.e. each system PID only depicts one plant system) with no interfacing system piping shown on the drawing. There is an “off sheet connector” that points to the interfacing system. Terminal component criteria must still be satisfied between the parent and interfacing systems.

4.4.4. The LR Engineer must coordinate with the preparers of interfacing systems to assure that interfacing piping and components are appropriately scoped, screened, and highlighted on the interfacing boundary drawing. Also the terminal component must be properly assigned with the (a)(2) symbol correctly placed on either the parent boundary drawing or interfacing system boundary drawing.

4.4.5. Dashed lines outlining “phantom” components should not be highlighted. System boundary flags or note boxes should be added to identify system boundary changes if the phantom components are in another system. These components will be depicted in solid lines on their parent boundary drawings. Piping and piping components depicted by dashed lines should be considered to be “phantom” and not highlighted.

4.4.6. Piping that is depicted in solid lines but which is assigned to another system should be highlighted consistent with its component function and the appropriate system boundary “Flag” should be applied to depict the system boundary. Highlighting should extend up to, but not including, the drawing transition arrow symbol.

Diablo Canyon License Renewal

TR-3DC
Fire Protection
License Renewal Position Paper

Revision 1
February 24, 2010

Fire Protection License Renewal Position Paper
Diablo Canyon

Approval Page

Revision	Prepared by:	Reviewed by:	Approved by:	Owner Accepted
0	Michelle Albright	David Hampshire Eric Blocher	Eric Blocher	--
Date	2/23/2007	9/15/2007	10/26/2007	--
1	Mo Palmowski	David Lipinski	David Kunsemiller	Philippe Soenen
Date	2/23/2010	2/24/2010	2/24/2010	3/3/2010

REVISION SUMMARY

Revision	Required Changes to Achieve Revision	Date
0	Initial Issue	10/26/07
1	Incorporated PCTFs: TR-PCTF-001, TR-PCTF-004, TR-PCTF-009, TR-PCTF-010, TR-PCTF-011, TR-PCTF-015, TR-PCTF-016, TR-PCTF-017, TR-PCTF-019, TR-PCTF-022, TR-PCTF-029, TR-PCTF-034, TR-PCTF-044, TR-PCTF-047, TR-PCTF-061; Added Main Condenser Hotwell in Table 3-1 for LRID 03; Added Portable Diesel Driven Fire Pumps in Table 3-1 for LRID 18; Revised Reactor Coolant System Inventory Control in Section 3.1 to explain addition of Containment Spray; Added LRID 25B as support system.. Reviewed fire protection sections of FSAR Rev 18, made changes to the revision status of FSAR references and added "(Ref 13)" in emergency lighting requirements of Section 2.1. Resolved Open Item regarding NFPA 805 coordination.	2/23/10

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1. PURPOSE OF POSITION PAPER

The License Renewal Rule, 10CFR54.4(a)(3) (Ref. 1), which only pertains to 10CFR50, requires that the structures, systems, and components (SSC's) relied on in safety analyses or plant evolutions to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10CFR50.48) be identified.

This position paper identifies the Diablo Canyon Power Plant SSC's relied upon in safety analysis or plant evaluations to perform a function that demonstrate compliance with 10CFR50.48, "Fire Protection" (Ref. 2). This document is for the use of license renewal project personnel engaged in the preparation, review, or approval of scoping and screening evaluations in support of license renewal feasibility study activities for Diablo Canyon Power Plant (DCPP).

2. FIRE PROTECTION CURRENT LICENSING BASIS (CLB) REQUIREMENTS FOR DIABLO CANYON

Fire Protection for the purposes of license renewal is an inclusive term to describe a station's ability to minimize the adverse effects of fires on structures, systems, and components important to safety. Based on General Design Criterion 3, "Fire Protection" of 10CFR50 Appendix A, fire protection includes:

- Proper design to minimize the probability and effect of fires and explosions,
- Control of transient and permanent storage of combustible material,
- Installation of fire detection and fighting systems and a program to manage their use, testing, and staffing, and
- Methods to bring the station to Safe Shutdown conditions regardless of the fire location.
- Firefighting systems designed to assure that their rupture or inadvertent operation does not significantly impair the safety capability of these structures, systems, and components.

2.1 FIRE PROTECTION REGULATORY REQUIREMENTS

10CFR50.48

10CFR50.48(a) requires that a fire protection plan be in place that satisfies General Design Criterion 3, "Fire Protection" of 10CFR50 Appendix A. 10CFR50.48(b) states that 10CFR50 Appendix R established fire protection features required to satisfy Criterion 3 of 10CFR50 Appendix A for nuclear power plants licensed before January 1, 1979. 10CFR50.48(b) also states that except for the requirements of Section III.G, III.J, III.L, and III.O, the provisions of 10CFR50 Appendix R (Ref. 3) do not apply to nuclear power plants licensed to operate before January 1, 1979, to the extent that fire protection features proposed or implemented by the licensee have been accepted by the NRC staff as satisfying the provisions of Appendix A to Branch technical Position (BTP) APCSB 9.5-1 reflected in NRC fire protection safety evaluation reports before the effective date of February 19, 1981.

General Design Criterion 3 of 10CFR50 Appendix A

General Design Criterion 3, Fire Protection, of 10CFR50 Appendix A states, “Structures, systems, and components important to safety shall be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions. Noncombustible and heat resistant materials shall be used whenever practical throughout the unit, particularly in locations such as the containment and control room. Fire detection and fighting systems of appropriate capacity and capability shall be provided and designed to minimize the adverse effects of fires on structures, systems, and components important to safety. Firefighting systems shall be designed to assure that their rupture or inadvertent operation does not significantly impair the safety capability of these structures, systems, and components.”

10CFR50 Appendix R Requirements

10CFR50 Appendix R establishes fire protection features required to satisfy Criterion 3 of 10CFR50 Appendix A. DCPP uses the information in 10CFR50.48(b) to determine the acceptable contents of the required fire protection plan. The NRC issued 10CFR50 Appendix R, in 1980, which contained requirements applicable to all plants. 10CFR50 Appendix R Sections III.G, III.J, III.L, and III.O described those requirements not addressed by Appendix A to BTP APCSB 9.5-1 and the Fire Hazards Analysis. DCPP has committed to meeting these additional requirements through the comparison located in DCM T-13 (Ref. 30).

Appendix R Section III.G (Fire Protection of Safe Shutdown Capability) Requirements

“1. Fire protection features shall be provided for structures, systems, and components important to Safe Shutdown. These features shall be capable of limiting fire damage so that:

a. One train of systems necessary to achieve and maintain hot shutdown conditions from either the control room or emergency control station(s) is free of fire damage; and

b. Systems necessary to achieve and maintain cold shutdown from either the control room or emergency control station(s) can be repaired within 72 hours.”

Diablo Canyon Comparison (partial response)

DCPP has demonstrated compliance with Section III.G of Appendix R for all areas with the exception of those in DCM T-13 Section 4.5, "Appendix R Deviations.” The method of compliance is provided in Calculation M-928, “10CFR50, Appendix R, Safe Shutdown Analysis” for each fire area (Ref. 19).

Appendix R Section III.J (Emergency lighting) Requirements

“Emergency lighting units with at least an 8-hour battery power supply shall be provided in all areas needed for operation of Safe Shutdown equipment and in access and egress routes thereto.”

Diablo Canyon Comparison (partial response)

Because eight hour battery backed lighting units are not provided at all operator manual action locations and access/egress routes, the emergency lighting system at DCPP is not in strict compliance with Section III.J. A request for exemption from 10CFR50 Appendix R Section III.J was originally submitted in NRC docket 50-275 (Unit 1) and 50-323 (Unit 2), "Pacific Gas and Electric Company Review of 10CFR50 Appendix R Section III.G, III.J and III.O." Based on the NRC review of Appendix 9.5D of DCPP FSAR 9.5, "Emergency Lighting Capability Evaluation to 10CFR50 Appendix R Section III.J" (Ref . 13) and clarifying description provided subsequently, the NRC staff approved the deviation to 10CFR50 Appendix R Section III.J in SSER 23 Section 9.6.1.18 (Unit 1) and SSER 31 Section 9.6.1.18 (Unit 2) (Refs. 4 & 5). The following are the fire zones approved for deviation from 10CFR50 Appendix R Section III.J:

1. Fire Area 3-B-3: Unit 1 Boron Injection Tank
2. Fire Area 3-C: Auxiliary Building E1 54, 64, and 73 ft.
3. Fire Area 3-H-1: Centrifugal Charging Pump Room
4. Fire Area 3-R: Unit 1 Spent Fuel Pool
5. Fire Area 14-D: Turbine Deck
6. Fire Area 28: Unit 1 Main Transformer
7. Fire Area 3-D-3: Unit 2 Boron Injection tank
8. Fire Area 3-I-1: Centrifugal Charging Pump Room
9. Fire Area 19-D: Turbine Deck
10. Fire Area 29: Unit 2 Main Transformer

Appendix R Section III.L (Alternative and dedicated shutdown capability) Requirements

"1. Alternative or dedicated shutdown capability provided for a specific fire area shall be able to
(a) achieve and maintain sub-critical reactivity conditions in the reactor;
(b) maintain reactor coolant inventory;
(c) achieve and maintain hot standby conditions for a PWR (hot shutdown for a BWR);
(d) achieve cold shutdown conditions within 72 hours; and
(e) maintain cold shutdown conditions thereafter."

Diablo Canyon Comparison (partial response)

DCPP has accepted the intent of Section III.L where it is applicable; there are no stated deviations from III.L in DCM T-13 Section 4.5, Appendix R Deviations.

Appendix R Section III.O (Oil collection system for reactor coolant pump) Requirements

"The reactor coolant pump shall be equipped with an oil collection system if the containment is not inerted during normal operation." (DCPP is not operated with an inerted containment.)

Diablo Canyon Comparison (partial response)
The technical requirements of Section III.O are not met because the oil holding tanks are not large enough to hold the entire lube oil system inventory for the four RCPs.

In its original evaluation of this system in the Part 50 SER, the NRC expressed concerns that an unmitigated fire involving lube oil could damage safety-related equipment in the vicinity. Consequently, DCPP agreed to install an oil collection system to provide a capability for collecting leakage from vulnerable components, and to provide an automatic sprinkler system to spray the areas around the pumps.

In addition, the NRC was also concerned that if overflowing lube oil ignited, the resulting fire would damage shutdown systems. However, the overflow line discharges into a trench that is sloped to channel any potential oil spill to the containment drain sump. Because the oil collection system is presently designed to withstand the safe shutdown earthquake and because there are no ignition sources in the anticipated flow path of the overflowing oil, the staff does not expect the oil to ignite.

Thus, the request for a deviation for the RCP oil collection system holding tanks was approved (Ref. 4).

BTP APCSB 9.5-1
BTP APCSB 9.5-1 identifies general requirements for multiple aspects of Fire Protection including the content, structure, and administration of the fire protection plan. The BTP cites the NRC's expectations that the appropriate National Fire Protection Association (NFPA) Codes and Standards will be met. The requirements in the Branch Technical Position envelope those in General Design Criterion 3 of 10CFR50 Appendix A.

Appendix A of BTP APCSB 9.5-1 provides detailed requirements to be incorporated in the Fire Protection Plan. It provides "preferred" and "alternative" approaches to methods of meeting the requirements. The preferred approach to meeting a requirement specified in BTP APCSB 9.5-1 is based on generic information. The NRC recognizes that Fire Protection Plans are specific to a particular site because of differences in design and layout. BTP APCSB 9.5-1 allows each licensee to propose an alternate method of complying with the requirements when a plant's unique design makes it impractical to incorporate the preferred approach.

2.2 DIABLO CANYON FIRE PROTECTION CLB

The Current Licensing Basis (CLB) for Fire Protection for DCPP consists of General Design Criterion 3 to 10CFR50 Appendix A, FSAR Appendix 9.5B, Table B-1, "Comparison of DCPP to Appendix A of BTP APCSB 9.5- 1", 10CFR50 Appendix R (as stated in DCM T-13), licensing conditions 2.C.(5) and 2.C.(4), and Design Criteria Memorandum S-18, "Fire Protection System". These documents and document sections identify the features required for DCPP to demonstrate compliance with 10CFR50.48. The basis for this conclusion can be derived from a review of 10CFR50.48.

10CFR50.48(a) requires that operating nuclear power plants have a fire protection plan that satisfies Criterion 3 of Appendix A. DCPP uses the information in 10CFR50.48(b) to determine the acceptable contents of the required fire protection plan.

10CFR50.48(b) states that Appendix R establishes fire protection features required to satisfy Criterion 3 of Appendix A. 10CFR50.48(b), however, allows the use of provisions of Appendix A to BTP APCSB 9.5-1 as an alternative to the requirements of Appendix R provided those provisions have been accepted by the NRC. In addition to the provisions of Appendix A to BTP APCSB 9.5-1, 10CFR50.48(b) imposes the provisions of Appendix R Sections III.G, J and O on plants licensed to operate prior to January 1, 1979. DCPP was licensed to operate on September 22, 1981 for Unit 1 and April 26, 1985 for Unit 2 (Refs. 7 & 8).

Based on the requirements of 10CFR50.48(b), it can be concluded that the fire protection plan is based on Appendix R and Appendix A to BTP APCSB 9.5-1. The DCPP requirement to comply with the requirements of Appendix R is a result of a commitment stated in the original Unit 1 and Unit 2 operating licenses. DCPP commitments to Appendix R may be changed without prior NRC approval as long as the changes do not adversely affect the capability to achieve and maintain safe shutdown (Refs. 7 & 8).

Diablo Canyon Fire Protection Licensing Bases Document

The primary CLB document for DCPP is the DCPP Final Safety Analysis Report Update (FSAR). Section 9.5.1 "Fire Protection System" (Ref. 10) of the DCPP FSAR provides most of the information concerning the design and testing of the fire protection system, and personnel qualifications. Appendices 9.5B and 9.5C through 9.5E provide information concerning the design and license bases, including comparisons to Appendix A to BTP APCSB 9.5-1 and to 10CFR50 Appendix R. Appendix 9.5A provides the DCPP Fire Hazards Analysis. The Fire Hazards Analysis shows that redundant safety systems required to achieve and maintain hot standby and cold shutdown are adequately protected against fire damage. The DCPP Fire Protection Design Criteria Memorandum summarizes the licensing bases for the DCPP Fire Protection Program. They are further summarized here below:

- Appendix A to BTP APCSB 9.5-1, Rev. 0
  DCPP FSAR Appendix 9.5B, Table B-1, "Comparison of DCPP to Appendix A of BTP APCSB 9.5- 1" (Ref. 12) provides a matrix of DCPP commitments to the regulatory requirements found in Appendix A to BTP APCSB 9.5-1 (Ref. 17). DCM S-18 identifies DCPP commitments to NFPA codes.
- 10CFR50 Appendix R
  DCPP DCM T-13, "Appendix R Fire Protection" provides DCPP commitments to the regulatory requirements found in Appendix R.
- Appendix R, Sections III.G and III.L (Safe Shutdown Analysis)
  DCPP FSAR Appendix 9.5A, "Fire Hazards Analysis" describes the capability of achieving and maintaining Safe Shutdown for a fire in any location at DCPP, as required by 10CFR50 Appendix R, Sections III.G and III.L
- Deviation Requests to 10CFR50 Appendix R
  FSAR Appendix 9.5A contains a deviation request section and conclusion per fire area subsection. Licensing conditions 2.C.(5) and 2.C.(4) (Refs. 7 & 8) to Facility

Operating Licenses DPR-80 and DPR-82, respectively, allows DCPP to make changes to the Fire Protection Program without prior NRC approval as long as the changes do not adversely affect the capability to achieve and maintain safe shutdown.

Diablo Canyon Final Safety Analysis Report
Information regarding systems and structures that are important to fire protection and post-fire safe shutdown can be found in FSAR Section 9.5.1, Appendix 9.5G, and associated tables.

Fire Protection Requirements Cited in Diablo Canyon Technical Specifications
Technical Specification 3.3.4, "Remote Shutdown System" requires certain instruments and components of the Remote Shutdown System to be Operable in Modes 1, 2 and 3. Although the Technical Specification is not specific to a fire in the control room, operability of the post-fire alternate hot shutdown panel would constitute compliance with this technical specification. The alternate hot shutdown panel constitutes DCPP compliance with Appendix R, Section III.L (Ref. 14).

Fire Protection Requirements Cited in Diablo Canyon Final Safety Analysis Report
FSAR Section 9.5.1 provides the fire protection requirement at DCPP. This section discusses the requirements for the fire suppression system, spray and/or sprinkler system, CO_2 systems, fire hose stations, yard fire hydrants and associated emergency response vehicle, and fire-rated assemblies.

Fire Protection Program Document
The DCPP Fire Protection Program is defined in Procedure OM8 (Ref. 20). This procedure describes the implementation and technical requirements of the Approved Fire Protection Program as described in the FSAR and SERs through Supplement 23.

3. SYSTEMS AND STRUCTURES REQUIRED TO COMPLY WITH FIRE PROTECTION

Systems and Structures required to comply with Fire Protection requirements are presented in the following position paper sections:

- Section 3.1 – Post-Fire Safe Shutdown Systems
- Section 3.2 – Fire Protection Systems
- Section 3.3 – Structures

3.1 POST-FIRE SAFE SHUTDOWN SYSTEMS

DCPP is required to achieve and maintain Safe Shutdown in the event of a fire as described in 10CFR50 Appendix R, Section III.G. The systems necessary for Safe Shutdown provide the following functions:

- Reactivity Control
- RCS Temperature Control
- RCS Pressure Control

- RCS Inventory Control
- Auxiliary Support Systems:
    - Class 1E Essential Power and Distribution
    - Emergency Diesel Generators
    - Safety Parameter Display System
    - Ventilation
    - Component Cooling Water
    - Saltwater and Chlorination System (Auxiliary Salt Water portion)

Several design features are utilized to ensure that post-fire safe shutdown can be achieved and maintained regardless of the location of a fire. There are two redundant trains of safety related systems powered by two redundant electrical sources, all of which are separated and protected according to Appendix R, section III.G.2. Post-Fire safe shutdown does not rely only on safety related equipment. All of the non-safety related equipment relied on for post fire safe shutdown has also been analyzed to meet the separation requirements of Appendix R, Section III.G.2. Calculation M-680 (Ref. 18) lists all of the equipment required for achieving and maintaining safe shutdown in the case of a fire anywhere in the plant. In some cases, a combination of Train A and Train B equipment may be needed to achieve and maintain safe shutdown. Train B is the protected train for alternate shutdown when the control room is not available due to a fire.

The following summarizes the CLB functional requirements and the Systems used for Post-Fire Safe Shutdown. More detail is provided in DCPP Calculation M-680, "Appendix R Safe Shutdown Equipment", Rev. 14.

Reactivity Control:
Reactivity control is required to ensure that the reactor is sub-critical. This can be accomplished by inserting the control rods and/or adding sufficient quantities of boron to the RCS. When the plant has to be shutdown immediately, due to a fire, the control rods are inserted by "reactor trip" in the control room. This brings the plant to a Hot Standby condition. For a fire in the control room, the plant may be maintained in hot standby until the transition to cold shutdown is initiated. Adding boron to the Reactor Coolant System (RCS) will be required to achieve cold shutdown. The following systems are required to achieve and maintain post-fire reactivity control:

- Turbine Steam Supply System (Main Steam portion) – Isolate to Control Cooldown
- Reactor Coolant – Borate
- Chemical and Volume Control – Borate
- Safety Injection System – Borate
- Nuclear Instrumentation (In-Core Instrumentation portion) – Control Inventory

Reactivity control is maintained from the initiating trip to cold shutdown conditions. Positive reactivity increases resulting from xenon decay and reactor coolant temperature decreases is compensated for by the addition of boron via the charging pumps taking suction from the Refueling Water Storage Tank (RWST).

The cooldown transition from hot standby to cold shutdown requires additional boration to maintain the required margin of shutdown reactivity. This additional boration compensates for the negative moderator coefficient and xenon decay.

Reactor Coolant System Temperature Control:
Reactor coolant system temperature control is required to transfer fission product decay heat from the reactor core at a rate such that specified acceptable fuel design limits and design conditions of the RCS pressure boundary are not exceeded. The following systems are required to achieve and maintain post fire reactor coolant system temperature control:

- Turbine Steam Supply System (Main Steam portion) – Isolate to Control Cooldown
- Reactor Coolant System – Control Inventory
- Auxiliary Feedwater – Control Inventory
- Main Feedwater – Control Inventory
- Residual Heat Removal – Remove Heat
- Saltwater and Chlorination System (Auxiliary Salt Water portion) – Remove Heat
- Component Cooling Water – Remove Heat

Reactor Coolant System Pressure Control:
Reactor coolant system pressure control is required to ensure that RCS pressure is high enough to prevent boiling of the coolant. As T_{avg} decreases, the required RCS pressure decreases to a point where the Residual Heat Removal (RHR) System can be utilized to cool down and maintain cold shutdown conditions. The following systems are required to achieve and maintain post fire reactor coolant system pressure control:

- Turbine Steam Supply System (Main Steam portion) – Isolate to Control Cooldown and Loss of Pressurizer Level
- Reactor Coolant System – Control Inventory
- Chemical and Volume Control – Provide Inventory
- Nuclear Instrumentation (In-Core Instrumentation portion) – Control Inventory
- Safety Injection System – Control Inventory

Reactor coolant system pressure control must be maintained to ensure that RCS pressure is:

- Maintained within the Technical Specification limits for RCS pressure/temperature requirements.
- Controlled to prevent peak RCS pressure from exceeding system design pressure.
- Maintained to ensure an adequate sub-cooling margin to preclude void formation within the reactor vessel during decay heat removal by natural circulation.

Reactor Coolant System Inventory Control:
Reactor Coolant System Inventory Control is achieved by ensuring sufficient makeup is provided to compensate for RCS fluid losses. These losses occur as a result of identified and unidentified leakage from the RCS and shrinkage of the RCS water volume during cooldown from Hot Standby to Cold Shutdown conditions. Diversion of the RWST inventory is prevented by terminating spurious operation of certain Containment Spray components that could result in a loss of RWST inventory. The following systems are required to achieve and maintain post fire reactor coolant system inventory control:

- Chemical and Volume Control – Provide Inventory
- Reactor Coolant System – Control Inventory
- Make-up Water System – Control Inventory
- Nuclear Instrumentation (In-Core Instrumentation portion) – Control Inventory
- Safety Injection System – Control Inventory
- Containment Spray System – Control Inventory

Auxiliary Support Systems:
Support is the ability to provide system components with operating environments: power, lubrication, and cooling that are necessary for accomplishing post fire safe shutdown functions. In addition, support systems provide preventive measures in support of the reactivity control, reactor coolant makeup, or heat removal functions. The following support systems are required to accomplish the support function:

- Class 1E Essential Power and Distribution
- Emergency Diesel Generators
- Safety Parameter Display
- Ventilation
- Component Cooling Water
- Saltwater and Chlorination System (Auxiliary Salt Water portion)

3.2 FIRE PROTECTION SYSTEMS

Fire Protection Systems provide fire detection, fire barrier or fire suppression functions to minimize the adverse effects of fires on SSCs important to safety. The Fire Protection Systems credited for this purpose are specified in DCPP DCM No. S-18 (Ref. 23). The DCPP FSAR states that the communication system is required for Fire Protection Support. The Fire Protection Systems that provide fire detection, fire barrier or fire suppression functions are:

- Carbon Dioxide System - automatic and manual hose stations (Ref 12 items E.5 and F.5/7))
- Fire Protection Water Supplies, Yard Mains, including Electric Fire Pumps 0-1, 0-2 and three portable diesel fire pumps
- Compressed Air System (Backup Air subsystem 25B), required for operability of Fire Protection Water system in Containment Building.

- Deluge Spray Systems – Gravity feed
- Standpipes; Fire Hose Stations
- Fire Alarm and Smoke Detection
- Wet Pipe Sprinkler Systems – Gravity feed
- Fire Rated Barriers and Associated Closure Assemblies (fire doors, fire dampers, equipment hatches and penetration seals)
- Reactor Coolant Pump Oil Collection System (Ref 12 item D.2(3))

Fire Rated Barriers and Associated Closure Assemblies

Fire rated assemblies include walls, floors/ceilings, cable raceway enclosures and other sealing devices in fire rated barriers separating redundant systems important to **p**ost **f**ire **s**afe **s**hut**d**own (PFSSD). Sealing devices include fire doors, fire dampers, cable and piping penetration seals. Where penetrations exist, they are sealed with a fire barrier seal material providing a fire resistance rating commensurate with the primary fire boundary. Fire Dampers are installed in HVAC openings through fire rated barriers. Fire Doors are installed where frequent access is necessary. Electrical cable raceways are protected by fire barrier wrap when necessary to provide separation of redundant PFSSD circuits within the same fire area.

Fire rated walls, floors, and ceilings are part of the structure and addressed as a structural component that provides a passive fire barrier function. The fire rated assemblies noted below provide a fire barrier function and are part of the fire protection system.

- Fire Doors (Refs. 32-38, Sheet 2)
- Fire Dampers (Refs. 21, Attachments 7.1 & 7.2; 39-57, Labeled FD)
- Fire Rated Penetration Seals (includes seismic gap seals with fire barrier function)
- Fire Barrier Raceway Wrap for Separation of Redundant PFSSD Circuits
- Equipment Hatches

Fire Protection Electrical Support

Fire protection electrical support is required to ensure the availability of an electrical power supply/source to those components and systems which are required for fire protection functions. The following systems provide this support:

- 4 kV System – provides distribution of AC power to switchgear and buses used in support of Safe Shutdown Paths.
- Class 1E 480V AC System – provides power to electric driven fire water pumps 0-1 and 0-2
- Non-Class 1E 120V AC System – power for fire water tank level indication and alarm, CO2 control panel, deluge valve solenoids, smoke detectors
- Non-Class 1E 125V DC System – power for plant wide fire alarm system, fire water isolation valve.

Fire Protection General Alarm
Fire alarms are required to be audible at the location of the fire and be distinctive. At DCPP, a fire alarm system is provided site wide as described in the emergency plan (Refs. 12 & 17). The Site Emergency and Containment Evacuation System provides this capability.

3.3 STRUCTURES

At DCPP, all fire areas are separated from all other fire areas by fire barrier construction and penetration closure assemblies that satisfy at least one of the following criteria: 1) are directly qualified by 3-hour fire endurance testing in accordance with criteria of the applicable controlling standard for the respective barrier assembly protection feature, 2) have been evaluated as providing and equivalent level of protection, or 3) have been evaluated as providing protection commensurate with the fire hazards present. Structural Fire Barriers consist of walls, ceilings, and floors of structures. Structures that provide fire barriers to protect equipment required for Safe Shutdown within the area from a fire outside the area or protect fire protection equipment to satisfy 10CFR50.48 requirements are:

- Auxiliary Building
- Containment (including pipeway)
- Pipeway Structure
- Fuel Handling Building
- Intake Structure and Intake Control Building
- Control Room (located in Auxiliary Building)
- Diesel Fuel Oil Pump Vaults and Structures
- Earthwork/Yard Structures
- Radwaste Storage Building
- Outdoor Water Storage Tank Foundations and Encasements
- Turbine Building

3.4 CASCADING OF SYSTEMS

First-level, primary support systems (or structures) that are necessary for the functioning of equipment credited to perform Safe Shutdown evolutions or otherwise demonstrate compliance with 10CFR50.48 “Fire protection” are included within the scope of 10CFR54. To comply with the License Renewal Rule, 10CFR54.4(a)(3), second-, third- and fourth-level support systems, back-up systems and systems or structures not explicitly credited in a current licensing basis (CLB) document to be available during this regulated event are not considered. However any support system that is specifically required for compliance with, or operation within, applicable NRC regulation is considered.

3.5 TABLE 3-1 AND TABLE 3-2

For the purpose of determining the systems and structures within the scope of license renewal per 10CFR54.4(a)(3), those systems that are required for Fire Protection are listed in Table 3-

1, and the associated structures are shown in Table 3-2. Each table includes the following columns:

Table 3-1

- LRID – system designator identified in TR-9DC LRID column
- System Name – system name identified in TR-9DC
- System Function – license renewal intended function for regulated event
- CLB Reference – Reference number from Section 4 (Reference Section) of position paper to be noted. As necessary a specific section of the reference may be identified

Table 3-2

- LRID – structure designator identified in TR-9DC LRID column
- Structure Name – structure name identified in TR-9DC
- Structure Function – license renewal intended function for regulated event
- CLB Reference – Reference number from Section 4 (Reference Section) of position paper to be noted. As necessary a specific section of the reference may be identified

4. REFERENCES

1. 10CFR54, "Requirements For Renewal Of Operating Licenses For Nuclear Power Plants"
2. 10CFR50.48, "Fire protection"
3. 10CFR50 Appendix R, "Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979"
4. Supplement 23 to the Safety Evaluation Report for Pacific Gas and Electric Company's application for licenses to operate DCPP Nuclear Power Plant, Units 1 and 2 (Docket No. 50-275)
5. Supplement 31 to the Safety Evaluation Report for the application by Pacific Gas and Electric Company for a license to operate DCPP Nuclear Power Plant Unit 2 (Docket No. 50-323)
6. Supplement 32 to the Safety Evaluation Report for Pacific Gas and Electric Company's application for licenses to operate DCPP Nuclear Power Plant, Unit 2 (Docket No. 50-323)
7. DCPP Unit 1 Composite Facility Operating License DPR-80, Rev. 31
8. DCPP Unit 2 Composite Facility Operating License DPR-82, Rev. 32
9. FSAR Section 3.1.6, "Reactivity Control," Revision 18, Dated September 2003
10. FSAR Section 9.5.1, "Fire Protection System," Rev. 18, Dated November 2006
11. FSAR Appendix 9.5A, "Fire Hazards Analysis," Rev.18
12. FSAR Appendix 9.5B, Table B-1, "Comparison of DCPP to Appendix A of BTP APCSB 9.5-1," Rev. 18, September 2003.
13. FSAR Appendix 9.5D, "Emergency Lighting Capability Evaluation to 10 CFR 50, Appendix R, Section III.J," Rev. 18
14. FSAR Appendix 9.5E, "10CFR50, Appendix R, Section III.L Alternative and Dedicated Shutdown Capability," Rev. 18
15. FSAR Appendix 9.5F, "Fire Barrier Figures," Rev. 18
16. FSAR Appendix 9.5G, "Equipment Required for Safe Shutdown," Rev. 18
17. Appendix A to Branch Technical Position (BTP) APCSB 9.5-1, Rev. 0, "Guidelines for Fire Protection for Nuclear Power Plants Docketed Prior to July 1, 1976" (Aug. 23, 1976)
18. Calculation M-680, "10CFR50, Appendix R, Safe Shutdown Equipment," Rev. 17
19. Calculation M-928, "10CFR50, Appendix R, Safe Shutdown Analysis," Rev. 16
20. DCPP Procedure OM8, "Fire Protection Program," Rev. 2B
21. STP M-70B, "Inspection and Testing of Fire Dampers," Rev. 12
22. DCPP Maintenance Rule, "Civil SSC Scope and Risk Significance," Rev. 0
23. DCPP Design Criteria Memorandum (DCM) No. S-18, Rev. 15B, Fire Protection System

24. DCPP Design Criteria Memorandum (DCM) No. T-1A, Rev. 6A, Containment Structure Exterior
25. DCPP Design Criteria Memorandum (DCM) No. T-1E, Rev. 3C
26. DCPP Design Criteria Memorandum (DCM) No. T-2, Rev. 6A, Auxiliary Building
27. DCPP Design Criteria Memorandum (DCM) No. T-3, Rev. 8, Structural Design of the Fuel Handling Building Steel Superstructure
28. DCPP Design Criteria Memorandum (DCM) No. T-4, Rev. 9, Structural Design of the Turbine Building
29. DCPP Design Criteria Memorandum (DCM) No. T-5, Rev. 7B, Structural Design of the Intake Structure
30. DCPP Design Criteria Memorandum (DCM) No. T-13, Rev. 4A, Appendix R Fire Protection
31. DCPP Design Criteria Memorandum (DCM) No. T-28, Rev. 6B, Outdoor Water Storage Tanks and Class 'S' Piping Vaults
32. DCPP Drawing 515220, "Operational Requirements with Doors With Functions Important to Safety," Rev. 49 (sht. 1) and 21 (sht. 2)
33. DCPP Drawing 515221, "Operational Requirements with Doors With Functions Important to Safety," Rev. 42 (sht. 1) and 20 (sht. 2)
34. DCPP Drawing 515222, "Operational Requirements with Doors With Functions Important to Safety," Rev. 59 (sht. 1) and 24 (sht. 2)
35. DCPP Drawing 515223, "Operational Requirements with Doors With Functions Important to Safety," Rev. 18 (sht. 1) and 40 (sht. 2)
36. DCPP Drawing 515224, "Operational Requirements with Doors With Functions Important to Safety," Rev. 39 (sht. 1) and 24 (sht. 2)
37. DCPP Drawing 515225, "Operational Requirements with Doors With Functions Important to Safety," Rev. 50 (sht. 1) and 22 (sht. 2)
38. DCPP Drawing 515226, "Operational Requirements with Doors With Functions Important to Safety," Rev. 30 (sht. 1) and 15 (sht. 2)
39. DCPP Drawing 515562, "Fire Barriers, Zones, and Fixed Suppression/Detection," Rev. 16
40. DCPP Drawing 515563, "Fire Barriers, Zones, and Fixed Suppression/Detection," Rev. 12
41. DCPP Drawing 515564, "Fire Barriers, Zones, and Fixed Suppression/Detection," Rev. 12
42. DCPP Drawing 515565, "Fire Barriers, Zones, and Fixed Suppression/Detection," Rev. 12
43. DCPP Drawing 515566, "Fire Barriers, Zones, and Fixed Suppression/Detection," Rev. 10
44. DCPP Drawing 515567, "Fire Barriers, Zones, and Fixed Suppression/Detection," Rev. 11
45. DCPP Drawing 515568, "Fire Barriers, Zones, and Fixed Suppression/Detection," Rev. 20
46. DCPP Drawing 515569, "Fire Barriers, Zones, and Fixed Suppression/Detection," Rev. 11
47. DCPP Drawing 515570, "Fire Barriers, Zones, and Fixed Suppression/Detection," Rev. 17
48. DCPP Drawing 515571, "Fire Barriers, Zones, and Fixed Suppression/Detection," Rev. 18
49. DCPP Drawing 515572, "Fire Barriers, Zones, and Fixed Suppression/Detection," Rev. 11
50. DCPP Drawing 515573, "Fire Barriers, Zones, and Fixed Suppression/Detection," Rev. 19

51. DCPP Drawing 515574, "Fire Barriers, Zones, and Fixed Suppression/Detection," Rev. 17
52. DCPP Drawing 515575, "Fire Barriers, Zones, and Fixed Suppression/Detection," Rev. 12
53. DCPP Drawing 515576, "Fire Barriers, Zones, and Fixed Suppression/Detection," Rev. 12
54. DCPP Drawing 515577, "Fire Barriers, Zones, and Fixed Suppression/Detection," Rev. 14
55. DCPP Drawing 515578, "Fire Barriers, Zones, and Fixed Suppression/Detection," Rev. 14
56. DCPP Drawing 515579, "Fire Barriers, Zones, and Fixed Suppression/Detection," Rev. 9
57. DCPP Drawing 515580, "Fire Barriers, Zones, and Fixed Suppression/Detection," Rev. 10
58. FSAR Section 10.4.7, "Condensate and Feedwater System," Rev. 18

TABLE 3-1

Systems Relied upon to Demonstrate Compliance with 10CFR50.48

LRID	System Name	System Function	CLB Reference
02	Condensate	Fire Protection Supply emergency fire water to the fire water compartment of the fire water transfer tank and pressurize the fire water hose reel system. Main Condenser Hotwell	Ref. 16, Section 2.d.1, 8.h Ref. 10, Section 9.5.1.2.3
03	Main Feedwater	RCS Temperature Control Provides a flow path to the Steam Generators for Auxiliary Feedwater.	Ref. 58
3B	Auxiliary Feedwater	RCS Temperature Control The AFW system is utilized in the post fire shutdown scenario to maintain the heat sink function of the steam generators and to serve as a cooldown system to maintain Hot Standby. The Auxiliary Feedwater pumps take suction from the condensate storage tank (or the essential service water system, if the condensate storage tank is unavailable) for delivery to the steam generators. The Firewater Tank, the inner tank of FWTT, serves as a supplemental supply to the Auxiliary Feedwater System.	Ref. 18, Section 4.1.2, 4.4.1.2a Ref. 31, Section 1.2.1
04	Turbine Steam Supply System (Main Steam portion)	Reactivity Control RCS Temperature Control RCS Pressure Control The MS System is isolated in a post fire shutdown to control secondary inventory.	Ref. 18, Section 4.1.1, 4.1.2, 4.1.3, 4.4.1.2h
07	Reactor Coolant System	Reactivity Control RCS Temperature Control RCS Pressure Control RCS Inventory Control The RCS is used in a post fire shutdown to transfer heat energy from the reactor core to the steam generators and to provide sufficient cooling of the reactor core in order to maintain its functional integrity.	Ref. 18, Section 4.1.1, 4.1.2, 4.1.3, 4.1.4, 4.4.1.2k
08	Chemical and Volume Control	Reactivity Control RCS Pressure Control RCS Inventory Control During post fire shutdown, the CVCS will maintain RCS inventory within the level of the pressurizer, place the plant in a cold shutdown reactivity condition, and provide RCP seal injection flow.	Ref. 18, Section 4.1.1, 4.1.4, 4.4.1.2d
09	Safety Injection	Reactivity Control RCS Pressure Control RCS Inventory Control Various SIS components and flowpaths are utilized during the post fire shutdown. RCS Makeup The borated water supply for the containment sprays and emergency core cooling system is drawn from the refueling water storage tank.	Ref. 18, Section 4.1.1, 4.1.3, 4.1.4, 4.4.1.2m Ref. 31, Section 1.2.1
10	Residual Heat Removal	RCS Temperature Control The RHR system is utilized in the post fire shutdown to transfer heat from the RCS to the CCW system to reduce the RCS temperature at a controlled rate.	Ref. 18, Section 4.1.2, 4.4.1.2l
14	Component Cooling Water System	RCS Temperature Control Auxiliary Support During a post fire shutdown, the CCW system is required to	Ref. 18, Section 4.1.2, 4.1.5.4

LRID	System Name	System Function	CLB Reference
		provide cooling for the charging pumps, RHR systems, and the RCP thermal barriers.	
16	Make-up Water System	RCS Inventory Control During a post fire shutdown, the MUS performs inventory control provided from the RWST.	Ref. 18, Section 4.1.4, 2.3.1.1
17	Saltwater and Chlorination System (Auxiliary Salt Water portion)	RCS Temperature Control The ASW is utilized during the post fire shutdown to supply cooling water from the ultimate heat sink (Pacific Ocean) to the CCW heat exchangers.	Ref. 18, Section 4.1.2, 4.4.1.2n, 2.3.1.3
18	Fire Protection	Support for SSC Credited in Safe Shutdown Fire Detection, Fire Suppression, or Fire Barrier Provides protection for equipment required for Safe Shutdown and other components important to safety. Includes the following fire protection systems: Fire Protection Water, Portable Diesel Driven Fire Pumps, Deluge Systems, Preaction Systems, CO2 Systems, Fire Alarm and Smoke Detection, Wet Pipe Systems, Raceway Wrap, Fire Doors, Fire Dampers, Fire Rated Penetration Seals. Decay Heat Removal The Transfer Tank, the outer tank of FWTT, provides the necessary protection to the Firewater Tank.	Ref. 11, Section 3 Ref. 23, Section 2.2.1, 2.2.2, 2.2.3, Ref. 10, Section 9.5.1.2.3, Ref. 31, Section 1.2.1
19	Liquid Radwaste System	Fire Protection Provides the Reactor Coolant Pump Oil Collection System to prevent a fire from defeating safety system functions. Provides floor drains, building sumps and pumps of adequate capacity for anticipated fire water runoff.	Ref. 12, Sections D.2(a)(3) and D.1(i)
21 21B	Diesel Generator System Diesel Fuel Oil Storage and transfer	Essential Electrical Support Supplies emergency power supply if offsite power is lost.	Ref. 18, Section 4.1.5.1
23 23B 23F	HVAC System Aux Bldg HVAC Control Room HVAC	Auxiliary Support In the Containment, Auxiliary, Turbine, and Fuel Handling Buildings several equipment can operate for 72 hours without HVAC. Operator actions were identified for those equipment that cannot function without HVAC. The ventilation exhaust fan associated with each ASW Pump provides necessary cooling for the pump during a post fire shutdown.	Ref. 18, Section 4.1.5.3, 4.1.5.5
25B	Compressed Air	Auxiliary Support Backup Air and N2 System for actuation of air operated valves for containment fire suppression.	Ref. 23
37	Nuclear Instrumentation System	Reactivity Control RCS Pressure Control RCS Inventory Control In-core instrumentation, such as rod cluster control assemblies, can compensate for the reactivity effects of temperature changes accompanying power level changes.	Ref. 9, Section 3.1.6.1
52	Safety Parameter Display System	Auxiliary Support During a post fire shutdown, monitoring provides direct readings of those plant process variables necessary for the plant operators to perform/control SSD functions. Instrumentation consists of steam generator level and pressure, pressurized level, RCS pressure and temperature, Condensate Storage Tank level & Boric Acid Storage Tank level.	Ref. 18, Section 4.1.5.2
60	Communications	Communications The direct-dial company telephone network provides the primary communication facility and the multichannel intercommunication system is the secondary communication facility in the event of a fire.	Ref. 10, Section 9.5.1.2.11, Ref. 12, Section D.5(c)
63	4 kV System	Electrical Support for SSC Credited in Safe Shutdown	Ref. 16

LRID	System Name	System Function	CLB Reference
		Provides distribution of AC power to components required for Safe Shutdown. Includes switchgear and buses used in support of Safe Shutdown Paths.	
64	480V System	Electrical Support for SSC Credited in Safe Shutdown Provides distribution of AC power to components required for Safe Shutdown. Includes load centers and MCCs used in support of Safe Shutdown Paths. Fire Protection Electrical Support Supplies non-vital AC power to the motor driven fire water pumps, jockey pumps, CO_2 and storage tank refrigeration compressors, and the vapor heater.	Ref. 16 Ref. 11, Fire Areas 5-A-1, 5-A-2, and 5-A-3 Ref. 23, Section 2.3.3.1
65	120V AC System	Electrical Support for SSC Credited in Safe Shutdown The 120V AC system provides control and instrument power to control panels used in support of Safe Shutdown Paths. Fire Protection Electrical Support Supplies non-vital AC power to the deluge valve solenoids, control panels for the CO_2 systems, smoke detectors, fire alarms, and fire water tank level indicators and alarms.	Ref. 16 Ref. 13, Section A.1 Ref. 23, Section 2.3.3.2
67	125V DC System	Electrical Support for SSC Credited in Safe Shutdown The 125 V DC System supplies power to support components required for Safe Shutdown. Included are distribution panels, DC control centers, batteries, and chargers used in support of Safe Shutdown Paths. Fire Protection Electrical Support Supplied DC power for communications and the containment fire water isolation valve solenoid and relay panels for the plant wide fire alarm system.	Ref. 16 Ref. 13, Section A.2 Ref. 23, Section 2.3.3.3
97	Site Emergency and Containment Evacuation System	Fire Protection General Alarm Provides site-wide, manually operated, fire alarm system.	Ref. 17 Ref. 12, Section E.1(c)

TABLE 3-2
Structures Relied upon to Demonstrate Compliance with 10CFR50.48

LRID	Structure Name	Structure Function	CLB Reference
ZA	Auxiliary Building	Structural Fire Barrier The Auxiliary Building provides structural and spatial fire barriers and protects equipment required for Safe Shutdown; houses control room.	Ref. 15, Figures 9.5F-5 thru 9.5F-11, 9.5F-16, 9.5F-17 Ref. 26, Section 2.3.6
ZC	Containment	Structural Fire Barrier The Containment Building provides support, shelter and protection for SCCs required for Post Fire Safe Shutdown (PFSSD.)	Ref. 22, Table 1, Ref. 15, Figures 9.5F-7 thru 9.5F-10, 9.5F-16 & 9.5F-17
ZF	Fuel Handling Building	Structural Fire Barrier The Fuel Handling Building provides structural fire barriers and spatial fire barriers that protect equipment required for Safe Shutdown.	Ref. 15, Figures 9.5F-8 thru 9.5F-10, 9.5F-16, 9.5F-17 Ref. 27*, Section 2.3.1
ZI	Intake Structure and Intake Control Building	Structural Fire Barrier The Intake Structure provides structural fire barriers that protect equipment required for Safe Shutdown.	Ref. 11, Fire Area IS-1 Ref. 29*, Section 2.3.1
ZJ	Control Room (located in Auxiliary Building)	Structural Fire Barrier The Control Room (located in the Auxiliary Building) provides structural fire barriers that protect equipment required for Safe Shutdown.	Ref. 15, Figure 9.5F-10
ZK	Diesel Fuel Oil Pump Vaults and Structures	Structural Fire Barrier The transfer pump vaults provide structural fire barriers that protect equipment required for Safe Shutdown.	Ref. 11, Fire Area 35-A & 35-B
ZM	Pipeway Structure	Structural Fire Barrier The Pipeway Structure provides support, shelter and protection for SSCs required for PFSSD.	Ref. 6, Section 4.1
ZQ	Earthwork/Yard Structures	Structural Support The Raw Water Reservoirs number 1A and 1B ensure that adequate fire water is available to confine and extinguish fires occurring in those portions of the facility containing safety-related equipment intended to be protected by fire water.	Ref. 12, Table B-1, Section E-2(c) & (d), Ref. 11, Section 4
ZR	Radwaste Storage Building	Structural Fire Barrier The Radwaste Storage Building shelters and protects a wet pipe sprinkler system where combustible materials are normally stored.	Ref. 12, Table B-1, Section F-14
ZT	Turbine Building	Structural Fire Barrier The Turbine Building provides structural and spatial fire barriers that protect equipment required for Safe Shutdown. The Turbine Building includes the Emergency Diesel Generator Rooms.	Ref. 15, Figures 9.5F-1 thru 9.5F-4, 9.5F-12 thru 9.5F-15 Ref. 28*, Section 2.3.1.2
ZW	Outdoor Water Storage Tank Foundations and Encasements	Structural Support Structural Fire Barrier The fire water storage and transfer tank foundation, condensate storage tank shell and foundation and the refueling water tank shell and foundation provide structural support and spatial and structural fire barriers that protect SSCs required for PFSSD.	Ref. 12, Section F-16 Ref. 31*, Section 2.3

LRID	Structure Name	Structure Function	CLB Reference
Notes: * Controlled reference used to provide additional details			
General Note: Component supports that are required to demonstrate compliance with Fire Protection regulations are addressed in LRID ZSUP			

Diablo Canyon License Renewal Feasibility Study

TR-6DC
Criterion (a)(2)
License Renewal Feasibility Study Position Paper

Revision 1~~0~~

~~December 31, 2007~~~~April 21~~January 28, 20~~09~~10

Criterion (a)(2) License Renewal Feasibility Study Position Paper
Diablo Canyon Power Plant

Approval Page

Revision	Prepared by:	Reviewed by:	Approved by:	Owner Acceptance
0	David Boortz	Eric Blocher	Eric Blocher	--
Date	October 11, 2007	November 28, 2007	December 31, 2007	--
1	Stan Shepherd	P.R. Soenen Al Saunders	David Kunsemiller	Philippe Soenen
Date	4/21/2009	Jan. 7/2010	January 28, 2010	February 10, 2010

~~**Open Item**~~

~~1. Identify safety related equipment in Turbine Building Fire Areas and update Appendix A as appropriate.~~

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Revision Summary

Revision	Required Changes to Achieve Revision	Date
0	Initial Issue	Dec. 30, 2007
1	Incorporated PCTF # 31 which added new Section 3.4 to account for abandoned in place piping and components. Incorporated PCTF # 57 which added new Section 3.5 to describe SISI targets and added associated references. Incorporated PCTF # 63 which	~~4/21~~11/16/2009

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	describes the results of the SISI Class I (SR) target evaluation that was performed for the Intake Structure and Turbine Building. Incorporated PCTF # 65 which clarified how potential (a)(2) spatial interactions are evaluated in the Turbine Building, revised Appendix A and deleted the open item. PCTF # 65 also revised the paragraph in Section 3.1, under "Intake Structure – Auxiliary Pump Rooms". Incorporated PCTF # 66 which clarified the discussion in Section 3.2 regarding how to perform (a)(2) connected piping evaluations. Incorporated PCTF # 67 which deleted the historical discussion in Section 2.0 regarding Scoping of Seismic II/I Piping Systems and added specific NEI 95-10 guidance regarding 1) Seismic II/I piping and supports, and 2) systems and components containing air/gas (added new subsections 3.1.1 and 3.1.2). Also included revision to Section 3.3 to refer to the DCPP boundary drawing legend for symbols to use for the various anchors.	

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1.0 PURPOSE OF POSITION PAPER

The License Renewal Rule, 10 CFR 54.4(a)(2), requires that all nonsafety-related structures, systems, and components (SSCs) whose failure could prevent satisfactory accomplishment of any of the safety-related functions performed by the SSCs in the scope of license renewal be themselves considered within the scope of license renewal. The industry has developed Appendix F of NEI 95-10, Revision 6, to address this issue. The guidance provided in NEI 95-10 Appendix F has been endorsed by the NRC in Regulatory Guide 1.188 Rev. 1.

This position paper identifies the Diablo Canyon process to be used to identify SSCs considered to satisfy NEI 95-10 Appendix F. This document is for the use of license renewal project personnel engaged in the preparation, review, or approval of scoping and screening evaluations in support of license renewal activities for Diablo Canyon Power Plant (DCPP).

2.0 CRITERION 54.4(a)(2) REQUIREMENTS FOR DCPP

Section 54.29 of 10 CFR Part 54 (Reference 2) states that a renewed license may be issued by the Commission if the Commission finds that actions have been or will be taken with respect to the matters identified in paragraphs (a)(1) and (a)(2) of this section such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the Current Licensing Basis (CLB), and that any changes made to the CLB in order to comply with this paragraph are in accord with the Atomic Energy Act and the Commission's regulations. These matters include managing the effects of aging during the period of extended operation to assure the functionality of structures and components that have been identified to require review under Section 54.21(a)(1).

The Statements of Consideration (SOC) for the Rule states that the objective of a license renewal review is to determine whether the detrimental effects of aging, which could adversely affect the functionality of systems, structures, and components (SSCs) that the Commission determines require review for the period of extended operation are adequately managed.

The SOC articulates the underlying philosophy of the Rule that during the period of extended operation, safety-related functions should be maintained in the same manner and to the same extent as during the current licensing term. Aging effects that could adversely impact on the ability of SSCs to maintain these safety-related functions during the period of extended operation should be evaluated.

~~In a letter dated December 3, 2001 (Reference 3), "Scoping of Seismic II/I Piping Systems" the NRC stated the following:~~

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~~*Section 54.4(a)(2) of the Rule states that all non-safety related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in Section 54.4(a)(1) should be included within the scope of the Rule. The [*Statements of Consideration*] (SOC) provides additional guidance related to this scoping criterion. Specifically, the SOC states that "To limit this possibility for the scoping category relating to nonsafety-related systems, structures, and components... An applicant for license renewal should rely on the plant's [*current licensing basis*]*~~

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~~*(CLB), actual plant-specific experience, industry wide operating experience, as appropriate, and existing engineering evaluations to determine those nonsafety-related systems, structures, and components that are the initial focus of the license renewal review. Consideration of hypothetical failures that could result from system interdependencies that are not part of the CLB and that have not been previously experienced is not required." (Federal Register, Volume 60, No. 88, 22467).*~~

~~In this letter, the NRC addressed their concern regarding the scoping of NSR SSCs interacting with SR SSCs, particularly as it related to seismic II/I piping. The NRC felt that license renewal applicants were not properly considering the effects of age-related pipe degradation and only included the seismically-designed pipe supports in the scope of license renewal. The NRC agreed with the applicants in that the seismically designed pipe supports should be within the scope of license renewal (WSLR), but added that there were numerous documented cases of erosion and corrosion pipe wall thinning issues and pipe failures in the industry. Based on this industry operating experience, the NRC concluded that pipe failures due to age-related degradation are not hypothetical, and therefore, not only should the supports be WSLR, but the NSR piping segments should be as well. This includes those piping segments in other than erosion-corrosion susceptible systems.~~

~~In a letter dated March 15, 2002 (Reference 4), "Guidance on the Identification and Treatment of Structures, Systems, and Components Which Meet 10 CFR 54.4(a)(2)", the NRC provided guidance for performing the scoping evaluation to supplement the position on the scoping of seismic II/I components. The NRC indicated that when evaluating the adverse impact of the failures of non safety-related SSCs, a distinction must be made between non safety-related SSCs that are connected to safety-related SSCs and those that are not connected to safety-related SSCs. For a non safety-related SSC that is connected to a safety-related SSC, the non safety-related SSC should be WSLR up to the first seismic anchor past the safety/non-safety interface.~~

~~For non safety-related SSCs that are not connected to safety-related SSCs, but have a spatial relationship such that their failure could adversely impact on the intended function of a safety-related SSC, two options were presented, a mitigative and a preventive option. With the mitigative option, the applicant should demonstrate that plant mitigative features (e.g., pipe whip restraints, jet impingement shields, spray and drip shields, seismic supports, flood barriers) are provided which protect SR SSCs from failures of NSR piping. The preventive option requires the applicant to include NSR piping segments in SR areas WSLR. The applicant may determine that, to ensure adequate protection of SR SSCs, a combination of mitigative features and NSR SSCs must be brought WSLR.~~

The industry has developed Appendix F of NEI 95-10, Revision 6 (Reference 1), to address this issue. The guidance provided in NEI 95-10 Appendix F has been endorsed by the NRC in Regulatory Guide 1.188. NRC expectations on non safety-related scoping are contained in Section 2.1.3.1.2 of NUREG 1800, Rev. 1, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plans."

This position paper documents a preventive approach for DCPP. The identification and scoping of the mitigative plant design features such as missile barriers, cranes, flood barriers, spray shields, and High Energy Line Break (HELB) protective features are evaluated as structural components and are not in the scope of this position paper. It is also important to note that the scoping Criterion

54.4(a)(2) specifically applies to those functions of Criteria 54.4(a)(1) and does not apply to functions identified in 54.4(a)(3).

3.0 SCOPING METHODOLOGY

The methodology described below is to be used to identify portions of NSR systems that could impact the function of SR SSCs within the scope of license renewal. Section 3.1 describes scoping of NSR SSCs not directly connected to SR SSCs. Section 3.2 describes scoping of NSR SSCs directly connected to SR SSCs. Section 3.3 provides information on identifying and documenting Terminal Components with respect to NSR SSCs determined to be within the scope of license renewal in sections 3.1 and 3.2.

3.1 NON-SR SSCs NOT CONNECTED TO SR SSCs

All structures containing SR components were considered as potential locations for SR/NSR interactions that could result in a Criterion (a)(2) intended function for spatial interaction. The following safety-related structures were considered:

- Auxiliary Building (contains control room)
- Containment
- Fuel Handling Building
- Turbine Building (contains emergency diesel generators)
- Intake Structure

It is the approach of DCPP to include all NSR SSCs in the Auxiliary Building, Containment, and the Fuel Handling Building as being within the scope of license renewal for Criterion (a)(2) spatial interaction considerations, except as discussed in Sections 3.1.1 and 3.1.2 below. As a result, no room by room or any similar structure breakdown in required for these structures.

For the purpose of determining the systems and components within the scope of license renewal per 10 CFR 54.4(a)(2) such that they can be identified in the license renewal boundary drawings, the spatial interactions will be evaluated by Fire Zone for the Intake Structure and the Turbine Building. Fire Zones are identified in Section 9B of the DCPP FSAR to better define and represent specific plant locations (e.g., rooms, corridors, etc.) to optimize the evaluations.

MELB

Unit 1 and 2 potential moderate energy line break (MELB) locations were evaluated and a plant walk-down identified which lines were in the area of SR SSCs. Results of the evaluation conclude that the protection of SR SSCs during a MELB is maintained, and furthermore, existing impingement shields are no longer required (References 6 and 7).

Flooding Due to Fire Protection Actuation

Flooding due to fire protection actuation would not occur to such a level that safe shutdown equipment would be endangered. Equipment is mounted on pedestals, minimizing any adverse effects of water suppression systems (Reference 11).

Intake Structure – Auxiliary Pump Rooms

The Intake Structure Auxiliary Pump Rooms, which coincide with Fire Zone 30-A-1, 30-A-2, 30-A-3, and 30-A-4, contain most~~all~~ of the ~~currently identified~~ SR SSCs within the structure. It was confirmed during scoping and screening that there are no mechanical SR SSCs outside the Auxiliary Pump Rooms, and associated fire zones, that would require inclusion of fluid-filled non-safety related SSCs within the scope of license renewal in accordance with Criterion (a)(2) for spatial interaction. DCPP confirmed that there are no cable trays carrying Class 1 cables in the Intake Structure and that SISI Class 1 cable targets in the Intake Structure are within hard piped conduit (see Section 3.5). Therefore there will be no potential (a)(2) spatial interactions with the cable from nonsafety-related fluid-filled SSCs located in the Intake Structure.

~~It is to be confirmed during scoping and screening that there are no SR SSCs outside the Auxiliary Pump Rooms, and associated fire zones, that would require inclusion of fluid-filled non-safety related SSCs within the scope of license renewal in accordance with Criterion (a)(2) for spatial interaction.~~

Turbine Building Fire Zones/Fire Areas

Turbine Building fire areas and corresponding fire zones which contain~~s~~ Safe Shutdown Equipment (SSE) and/or SR SSCs are identified in Appendix A (References 8, 9, and 10). For each fire zone that is known or found to contain SR SSCs, all fluid-filled NSR SSCs in that fire zone will be within the scope of license renewal in accordance with criterion (a)(2) for spatial interaction, with the exception of four instances that are described in detail in Section 3.5.

The DCPP Fire Zone/Area layout drawings together with descriptions of the Fire Zones/Areas in the FSAR are utilized to assist the LR System Engineer determine if any safety-related components are located within the Turbine Building. DCPP FSAR Table 1.6-1 lists design drawings that are incorporated by reference into the FSAR. In accordance with this table, Fire Area drawings 515562 through 515580 have replaced FSAR Figures 9.5F-1 through 9.5F-19. Therefore, these drawings (515562 through 515580) are used for determining fire areas and boundaries. Another tool is the Mechanical Equipment Location Plans (e.g., drawing 57718). An additional tool is the SISI Program Manual which identifies Class I and Class II targets in the Turbine Building (see Section 3.5, SISI Targets).

If walls or other barriers protect SR equipment from potential (a)(2) spatial interaction considerations, then the SR equipment may be excluded as a target for potential (a)(2) spatial interactions. For example, the Emergency Diesel Generators which are located within reinforced concrete missile protection walls, within the Turbine Building, are excluded from being targets for potential (a)(2) spatial interactions with NSR SSCs that are located outside those walls. SR equipment within concrete walls or barriers need not be evaluated for potential spatial interactions with NSR SSCs that are located outside the walls or barriers.

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See Section 3.5 for SR SSCs in the Turbine Building that have been excluded from ~~impacting~~ potential (a)(2) spatial interactions in the Turbine Building.

3.1.1 Non-Seismic and Seismic II/I Piping and Supports

NEI 95-10 (Reference 1), App F, Section 5.2.2.3, provides the following scoping guidance.

> From a review of earthquake experience data, including experience with aged pipe, the following conclusions can be made:
>
> - No experience data exist of welded steel pipe segments falling due to a strong motion earthquake
> - Falling of piping segments is extremely rare and only occurs when there is a failure or unzipping of the supports
> - These observations hold for new and aged pipe
>
> As long as the effects of aging on the supports for these piping systems are managed, falling of piping sections, except for FAC failures, is not considered credible, and the piping section itself would NOT be in scope for 54.4(a)(2) due to the physical impact hazard (although the leakage or spray hazard may still apply).
>
> Other potential physical impacts from swaying or other piping system movements due to seismic events or water hammer are not age-related, and therefore do not need to be considered in scope for 54.4(a)(2). Any of these potential physical impacts that are identified should be considered CLB/-design issues and addressed via a plant's existing corrective action process.

The supports for all piping, wet or dry, in proximity to SR SSC's, are in-scope with Intended Function = FS01 (addressed by Structural in LRID ZSUP).

3.1.2 Systems and Components Containing Air/Gas

NEI 95-10 (Reference 1), App F, Section 5.2.2.1, provides the following scoping guidance.

> Air and gas systems (non-liquid) are not a hazard to other plant equipment. Industry operating experience (such as NUREG-1801, industry tools documents, and other LRA SERs) for systems containing air/gas, has shown no failures due to aging that have adversely impacted the accomplishment of a safety function. In addition, there are no credible aging mechanisms for air/gas systems with dry internal environments. A review of site-specific operating experience should be performed to verify this assumption. The results of this site-specific review should be maintained in a retrievable and auditable form. Additionally, components containing air/gas cannot adversely affect safety-related SSCs due to leakage or spray. Therefore, these systems are not considered to be in scope for 54.4(a)(2).

3.2 NON-SR SSCs CONNECTED TO SR SSCs

Comment [PNS31]: I deleted the word "impacting" because it seem to read like it is a concern for SR components to impact NSR components. I'm not sure if the current rewrite captures the original intent.

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For non-safety SSCs directly connected to safety-related SSCs, the non-safety piping and supports, up to and including the first seismic or equivalent anchor beyond the safety/non-safety interface, are within the scope of license renewal per 10 CFR 54.4(a)(2) for structural integrity. For this purpose, the "first seismic or equivalent anchor" is defined according to the guidance of NEI 95-10, Rev. 6, Appendix F, section 4, to be one of the following:

Seismic or Equivalent Anchor

- An actual seismic anchor that ensures forces and moments are restrained in three orthogonal directions.
- An equivalent anchor as defined by DCPP CLB restraints the pipe from all translational and rotational movements (Reference 12)
- An equivalent anchor consisting of a large piece of plant equipment (e.g., a heat exchanger) or a series of supports that have been evaluated as a part of a plant specific piping design analysis to ensure that forces and moments are restrained in three orthogonal directions.
- An equivalent anchor such that a combination of restraints or supports encompasses at least two (2) supports in each of three (3) orthogonal directions.

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Alternates to Seismic Anchor or Series of Equivalent Anchors

- A base-mounted component (e.g., pump, heat exchanger, tank, etc.) that is a rugged component and is designed not to impose loads on connecting piping.

- A flexible connection that decouples the piping system (i.e. does not support loads or transfer loads across it to connecting piping).

- A free end of NS piping, such as a drain pipe that ends at an open floor drain.

- NSR piping runs that are connected at both ends to SR piping and include the entire run of NSR piping.

- A point where buried piping exits the ground. A determination that the buried piping is well founded on compacted soil that is not susceptible to liquification must be made.

- A smaller branch line that does not impose loads on larger piping and does not support larger piping.

All Class I piping at DCPP is seismically anchored. When there is a connection between Class I and Class II piping, the anchor rating defaults to Class I and therefore is seismically qualified. Analysis is completed on Class II piping anchors to determine if seismic qualification is needed. When evaluating a specific line on a DCPP P&ID one must refer to the color-coded corresponding P&ID, kept only in hardcopy, on site to determine the stress isometric drawing associated with the given line number. The hardcopy-only stress isometric drawing provides seismic anchor locations and reference to the anchor number. Anchor numbers can be used in the Plant information Management System (PIMS) to identify associated calculations and supplemental information.

3.3 TERMINAL COMPONENT IDENTIFICATION AND DOCUMENTATION

Terminal Components are defined as those plant components serving as the terminus for a section of NSR system within the scope of license renewal based on the criteria of sections 3.1 or 3.2. These components are specifically identified to justify and document the scoping decision process for the purpose of simplifying future reviews. Terminal Components are flagged in the LRDMT and, where appropriate, marked on the LR boundary drawings. The guidance of NEI 95-10, Appendix F, will be used to identify Terminal Components per sections 3.1 and 3.2 above.

Structural Integrity Attached
For non-safety components directly connected to safety-related components (structural integrity attached) identified per section 3.2 that are Terminal Components, check the “Tm Cmp (dc)” box in the LRDMT and fill in the appropriate reference information in the popup that appears. Mark the Terminal Component location on the LR boundary drawing using ~~a~~ the appropriate triangle symbol

from the DCPP LR Boundary Drawing Legend (LR-DCPP- 01-106701-00). ~~encapsulating the appropriate code per the list below.~~ The following ~~codes~~ termination list is summarized from NEI 95-10 Appendix F and is consistent with the LRDMT Terminal Component drop-down selection list and the ~~will apply to both the LRDMT and the~~DCPP LR ~~boundary~~ Boundary ~~drawings~~ Drawing Legend~~(note that F.4.c situations need not be marked on the drawing as they are obvious)~~:

- F.4.1 - Seismic Anchor
- F.4.2 - An equivalent anchor as defined in the CLB.
- F.4.3 - An equivalent anchor consisting of a large piece of plant equipment or a series of supports that may have been evaluated as a part of a plant specific piping design analysis to ensure that forces and moments are restrained in three orthogonal directions.
- F.4.4 - An equivalent anchor such that a combination of restraints or supports encompasses at least two supports in each of the three orthogonal directions.
- F.4.a - A base mounted component that is a rugged component and is designed not to impose loads on connecting piping.
- F.4.b - A flexible connection that decouples the piping system.
- F.4.c - A free end of NS piping, such as a drain pipe that ends at an open floor drain.
- F.4.d - NS piping runs that are connected at both ends to SR piping and include the entire run of NS piping.
- F.4.e - A point where buried piping exits the ground.
- F.4.f - A smaller branch line that does not impose loads on larger piping and does not support larger piping.

Spatial Interactions
For non-safety components not directly connected to safety-related components identified per section 3.2 that are Terminal Components, check the "Tm Cmp (dc)" box in the LRDMT and fill in the appropriate reference information in the popup that appears. Mark the Terminal Component location on the LR boundary drawing using a hexagon symbol encapsulating the notation "SI" (for Spatial Interaction) (note that FM0802 situations need not be marked on the drawing as they are obvious). The following codes will apply to the LRDMT:

- FM0801 - Liquid-filled portion of system transitions to an area with no SR SSCs that can be affected.
- FM0802 - End of the NSR line.
- FM0803 - System becomes isolated or dry at this point.

3.4 ABANDONED-IN-PLACE PIPING AND COMPONENTS

When abandoned-in-place piping and components are evaluated in accordance with criterion (a)(2) the following guidance is provided.

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- Abandoned-in-place piping and components should be considered to be in-scope (assuming it would be in-scope if it were not abandoned) unless the following criteria are met:
    (1) The piping is cut and capped and thus completely isolated from incoming and outgoing piping;
    (2) The piping is isolated by two locked closed valves in series and there is a locked open telltale drain valve that assures that the piping remains dry.
- If abandoned-in-place piping is excluded from being in-scope and does not meet (1) or (2) above then there must be plant documentation referenced that justifies the exception from scope.
- In other cases, such as with closed single or double isolation valves, the plant cannot say for certain that the valves do not leak and that there is no water in the abandoned piping. As a result the piping must be considered to be in-scope. There is a precedent for the NRC to ask questions regarding abandoned piping and for positive proof that the piping is dry.
- Piping and components that are identified as "Abandoned but Active" should be considered to be in-scope (assuming it would be in-scope if it were not abandoned) and assigned the component functions of FS15 and/or FM08 as appropriate unless the abandoned piping and components meet the criteria of (1) or (2) above.
- Abandoned-in-place SR components that do not meet (1) or (2) above should be highlighted Red, not Green, and put in scope for FM08 not FM01, and identified as a Problem Component per PI-1, Section 4.7.
- Abandoned piping, by definition, cannot perform any (a)(1) or (a)(3) function.

3.5 SISI TARGETS

Per the DCPP Seismically Induced Systems Interactions (SISI) Manual (Reference 13), Section 1.1, the SISI Program was implemented at DCPP to address R.G. 1.29 issues, including the seismic 2 over 1 issue which specifies that nonsafety-related SSCs should be seismically designed if their failure could jeopardize the functioning of safety-related components in a seismic event. The SISI Program was a condition imposed on the Operating Licenses for DCPP because they had not committed to R.G. 1.29.

SISI targets are designated as Class I or Class II. Based on a review of the SISI Manual, SISI Class II targets were included in the SISI Program to satisfy the R.G 1.29 "2 over 1" issue. For example, Section 4.7.5 of the SISI Manual states that mechanical Class II components may be seismically qualified to ensure its pressure boundary integrity after a seismic event.

Both SISI Class I and Class II targets are included in scope of License Renewal. Class I Mechanical, Electrical and I&C components at DCPP have a "Q" classification in the DCPP database, meaning that the QA provisions of Appendix B to 10CFR50 apply (Reference: 14, Table 1). In the LRDMT, the SISI Class I targets are captured in scope due to their "Q" classification which in the LRDMT translates to "SR" (SR Box checked). In general, all SR components are in scope of LR.

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SISI Class II targets are included in scope of LR based on conservatism and based on PG&E submittals to the NRC that describe SISI targets as being safety related or important to safety. For example, in Section 1.1 of Reference 15, it states that a target is considered a structure, system or component important to safety. SISI Class II Mechanical, I&C and Piping targets are identified in the SISI Manual by device numbers. Device numbers are similar to component numbers and correlate to component numbers. In the LRDMT, Class II targets are captured in scope by checking applicable component numbers in scope in accordance with the list of Class II SISI targets developed based on a review of the SISI Manual. The Intended Function for SISI Class II targets is FS01, "Structural Support." The (a)(2) criterion states that nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of any of the functions identified in Section 54.4(a)(1) should be included within the scope of the Rule.

Evaluation of SISI Targets for Potential Impact on (a)(2) Spatial Interactions in the Turbine Building and Intake Structure

An evaluation was performed on the SISI Class I (SR) targets in the Turbine Building (those not located within missile or barrier protected walls in the Turbine Building) and Intake Structure for their potential impact on (a)(2) spatial interactions due to fluid-filled nonsafety-related SSCs within the Turbine Building and Intake Structure. Walkdowns were performed and photographs were taken where additional information was requested to determine if these targets could bring into scope any nonsafety-related components as a result of potential (a)(2) spatial interactions. The results confirmed that these targets did not bring into scope any nonsafety-related SSCs as a result of potential (a)(2) spatial interactions (References 19, 20). Specific details are described below.

1. Class I Cable Trays and Conduit

It was confirmed by DCPP that there are no cable trays carrying Class 1 cables in the Turbine Building and Intake Structure. DCPP also confirmed that SISI Class 1 cable targets in the Turbine Building and Intake Structure are within hard piped conduit (Reference 19). Therefore there are no potential (a)(2) spatial interactions with the cable from nonsafety-related fluid-filled SSCs located in the Turbine Building and Intake Structure.

2. PT-505, -506 Instrument Tubing

The instrument tubing associated with PT-505, -506 (transmitters providing redundant first stage impulse pressure input from the HP turbine to the reactor trip circuit, and providing input to the main steam dump control circuitry and input to ATWS Mitigation System Actuation Circuitry (AMSAC)) is a SISI Class 1 target. The tubing runs in the Turbine Building from the transmitters located in the CCW Heat Exchanger vaults on El. 85' up to the HP turbines on El. 140'. These transmitters are fail-safe (Reference 16). AMSAC provides a way to trip the main turbine, initiate auxiliary feedwater flow and isolate steam generator blowdown in the event that an ATWS results in the loss of the secondary heat sink (Reference 17). After discussions with the turbine engineer, AMSAC system owner, and former Senior Reactor Operators, it was determined by DCPP that the tubing is not required to shut down the reactor and maintain it in a safe shutdown condition, nor is it required to prevent or mitigate the consequences of accidents

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that could result in potential offsite exposure. A drop in pressure, or equivalent reading, will result in AMSAC initiating a reactor trip that will bring the plant to a safe shutdown condition (Reference 20). Therefore the tubing is not a target for (a)(2) considerations in the Turbine Building.

3. EDG Engine Exhaust Lines above Turbine Building El. 140’

The EDG engine exhaust lines that run above the turbine deck on El. 140’ in the Turbine Building are safety-related Class I and are in scope of LR. Their function is to provide a directed flow path for EDG engine exhaust to the atmosphere. Below turbine deck El. 140' the lines are within concrete walls and thus protected from the adverse spatial interaction effects of postulated failure of nonsafety-related equipment, but above the turbine deck the lines are not enclosed within concrete walls or other barriers. The EDG engine exhaust lines are not described in the FSAR and there are no missile protection requirements for these lines (FSAR Section 3.3.2.3.2.8 discusses the impact of tornado missiles on the diesel generator compartment ventilation exhaust plenum which runs outside the Turbine Building, but no mention is made of missile protection for the EDG engine exhaust lines in the FSAR). The EDG engine exhaust lines are SISI targets per Appendix 1 of the SISI Manual (Reference 13); however only the snubbers on the lines are stated to be potentially vulnerable for the seismic event. The HELB analysis (Reference 18) does not mention the EDG engine exhaust lines as requiring protection from high energy line missiles or pipe whip. Since the only function of these lines is to provide a directed flow path for EDG engine exhaust to the atmosphere, the maintenance of an airtight pressure boundary is not required. The primary requirement is that damage to the line would not result in blockage of the flow path. It is unlikely that damage to the exhaust lines by fluid spray from postulated failure of NSR fluid-filled components on the turbine deck, such as the LP turbine and the associated cross over steam piping, would block the flow path sufficiently to have a significant impact on the safety function of the lines. Therefore the piping is not considered a target for potential (a)(2) spatial interaction considerations in the Turbine Building. The EDG engine exhaust lines are subject to periodic external surfaces monitoring per AMP XI.M36 thereby ensuring that any external aging effects will not go unnoticed.

4. HVAC Supply and Exhaust Ducts on El. 140’and El. 119’ in the Turbine Building that Provide Ventilation Air to the Vital 480 V Switchgear Rooms

The same rationale as described above for the EDG engine exhaust lines applies to the HVAC supply and exhaust ducts on El. 140’and El. 119’ in the Turbine Building that provide ventilation air to the vital 480 V switchgear rooms. The ducts provide a safety-related function and are in scope of LR. The function of the ducts is to provide a directed flow path for supply and exhaust ventilation air to and from the vital 480 V switchgear rooms. The HVAC ducts are SISI targets per Appendix 1 of the SISI Manual (Reference 13); however they are only described as having limited vulnerability in the Manual. Similar to air/gas pipe systems, HVAC ducts are not a hazard to other plant equipment (see Section 3.1.2). The only spatial interaction concern is falling. The ducts are seismically supported and protected from seismically induced interactions by the SISI Program. Since the only function of the ductwork is to provide a directed flow path to and from the switchgear rooms, the maintenance of an airtight pressure boundary is not required. The primary requirement is that damage to the ductwork would not result in blockage

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of the flow path. It is unlikely that damage to the ducts by fluid spray from postulated failure of NSR fluid-filled components on the turbine deck, such as the LP turbine and the associated cross over steam piping, would block the flow path sufficiently to have a significant impact on the safety function of the ducts. Therefore the ductwork is not considered a target for potential (a)(2) spatial interaction considerations in the Turbine Building. The HVAC ducts are subject to periodic external surfaces monitoring per AMP XI.M36 thereby ensuring that any external aging effects will not go unnoticed.

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4.0 REFERENCES

1. NEI 95–10, Industry Guidelines for Implementing the Requirements of 10. CFR Part 54–The License Renewal Rule, Revision 6, June 2005
2. 10 CFR 54, "Requirements for Renewal of Operating License for Nuclear Power Plants," May 8, 1995
3. "License Renewal Issue: Scoping of Seismic II/I Piping System, "letter from Grimes (NRC) to Nelson (NEI) and Lochaum (UCS), December 3, 2001
4. NRC Letter, “Guidance on the Identification and Treatment of Structures, Systems, and Components Which Meet 10 CFR 54.4(a)(2)” March 15, 2002
5. NUREG – 1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants, Rev 1"
6. Moderate Energy Line Breaks Re-analysis Report, DCPP Unit 1
7. Moderate Energy Line Breaks Re-analysis Report, DCPP Unit 2
8. Attachment G, M-680, Rev. 14, Unit 2 Safe Shutdown Equipment
9. Attachment C, M-680, Rev. 14, Unit 1 Safe Shutdown Equipment
10. DCPP Unit 1 and 2 Fire Zone Delineation Drawings
11. FSAR Appendix 9.5B, table B-1, Section D.1.i
12. Diablo Canyon Design Criterion Memorandum, T-25
13. Seismically Induced Systems Interactions (SISI) Manual, Rev. 9, dated July, 2007.
14. DCPP Q-List, dated September 2008.
15. DCPP letter from Philip A. Crane to NRC John F. Stoltz, dated 9/16/80, entitled "Revision 4 to Report Entitled, Description of the Systems Interaction Program for Seismically Induced Events.”
16. DCM S-04, Turbine Steam Supply System, Rev. 26
17. DCM S-34B, ATWS Mitigation System Actuation Circuitry (AMSAC), Rev. 4
18. DCM T-12, Pipebreak (HELB/MELB), Flooding and Missiles Rev. 15A

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19. LRFS-09-011, Letter from David Boortz to David Kunsemiller, dated April 8, 2009.

20. LRFS-09-012, Letter from David Boortz to David Kunsemiller, dated April 8, 2009.

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Appendix A

Turbine Building Fire Areas/Zones Containing SSE and/or SR SSCs

Unit 1				Unit 2			
Fire Area	**Fire Zone**	**SSE**	**SR**	**Fire Area**	**Fire Zone**	**SSE**	**SR**
10	-	N	~~TBD~~Y	18	-	N	~~TBD~~N
11-D	-	N	~~TBD~~Y	20	-	N	~~TBD~~Y
13-D	-	N	~~TBD~~Y	21	-	N	~~TBD~~Y
13-E	-	N	~~TBD~~Y	22C	-	N	~~TBD~~Y
13-F	-	N	N	24-D	-	N	~~TBD~~N
14-B	-	N	N	TB-7	19-A	N	~~TBD~~Y
15	-	N	~~TBD~~N		19-B	N	~~TBD~~N
17	-	N	N		19-C	N	~~TBD~~N
S-1	-	N	N		19-D	N	Y
TB-1	11-A-1	Y	Y		19-E	N	Y
	11-A-2	N	~~TBD~~Y		23-E	N	~~TBD~~N
TB-2	11-B-1	Y	Y		S-6	N	N
	11-B-2	N	~~TBD~~Y	TB-8	22-A-1	Y	Y
TB-3	11-C-1	Y	Y		22-A-2	N	~~TBD~~Y
	11-C-2	N	~~TBD~~Y	TB-9	22-B-1	Y	Y
TB-4	12-A	N	~~TBD~~Y		22-B-2	N	~~TBD~~Y
	13-A	Y	Y	TB-10	23-A	N	~~TBD~~Y
TB-5	12-B	N	~~TBD~~Y		24-A	Y	Y
	13-B	Y	Y	TB-11	23-B	N	~~TBD~~Y
TB-6	12-C	N	~~TBD~~Y		24-B	Y	Y
	13-C	Y	Y	TB-12	23-C-1	N	~~TBD~~Y
TB-7	12-E	N	~~TBD~~N		24-C	Y	Y
	14-A	N	~~TBD~~Y	TB-17	22-C-1	Y	Y
	14-C	N	~~TBD~~N		22-C-2	N	~~TBD~~Y
	14-D	N	Y	TB-13	23-C-1	N	~~TBD~~Y
	14-E	Y	Y		24E	N	~~TBD~~N
	16	N	N		25	N	~~TBD~~N
					S-7	N	~~TBD~~N

Notes:

~~1.~~ **1. Y = Yes, N = No, based on SISI target locations. The SISI Program is part of the CLB.**

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PAM COB Procedure Cover Sheet

Review of Time-Limited Aging Analysis (TLAAs)

PAMCOBP - PI-3 – 02/07 – Rev 1

Revision Summary:
  Revision 0 – Initial Issue
  Revision 1 – see page i

Prepared by: Eric Blocher

Approved by: Paul F Carley

Date Approved: February 14, 2007

Project Instruction PI-3

Review of Time-Limited Aging Analyses (TLAAs)
for
STARS License Renewal Projects

Revision 1

February 7, 2007

Review of Time-Limited Aging Analysis (TLAAs)
for
STARS License Renewal Projects

Approval Page

Revision	Prepared by:	Reviewed by:	Approved by:
0	Donald H. Stevens	Tony Grenci	Eric A. Blocher
Date	October 1, 2004	October 01, 2004	October 01, 2004
1	Donald H. Stevens	Tony Grenci	Eric Blocher
Date	February 6, 2007	February 7, 2007	February 7, 2006

Revision Summary

Revision	Required Changes to Achieve Revision	Date
0	Issued for use.	Oct 01, 2004
1	Revised text and examples to incorporate lessons learned and to improve generic applicability. Deleted requirement for a separate LRA reference list and AMP Appendix in the TLAA report. Corrected Footnote 2, on applicability of Westinghouse GTRs. Changed 4.7.2 on use of GTRs from shall to may. Added 4.9.5 on "further evaluations." Added note in word search that some words may be too general. Corrected minor cross-reference errors, clarified nomenclature, incorporated editorial changes, revised definitions, and updated references.	Feb 07, 2007

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1.0 SCOPE

Note:
Boxes contain examples, for information only, which are not specifically required by this instruction.

This instruction provides guidance for review, evaluation, and determination of dispositions of possible time-limited aging analyses (TLAAs) as defined by 10 CFR 54 (Reference 1, the license renewal rule or the rule). This instruction is in support of the License Renewal Applications (LRAs) prepared for the Strategic Teaming and Resource Sharing STARS) nuclear stations.

The STARS plants are all pressurized water reactors (PWRs). This instruction therefore omits details appropriate only to boiling water reactors (BWRs).

1.1 Purpose

This instruction provides directions for completing TLAA evaluations that meet the requirement of 10 CFR 54.21(c) as follows:

> (c) An evaluation of time-limited aging analyses.
>
> (1) A list of time-limited aging analyses, as defined in §54.3, must be provided. The applicant shall demonstrate that --
>
> (i) The analyses remain valid for the period of extended operation;
>
> (ii) The analyses have been projected to the end of the period of extended operation; or
>
> (iii) The effects of aging on the intended function(s) will be adequately managed for the period of extended operation.
>
> (2) A list must be provided of plant-specific exemptions granted pursuant to 10 CFR 50.12 and in effect that are based on time-limited aging analyses as defined in §54.3. The applicant shall provide an evaluation that justifies the continuation of these exemptions for the period of extended operation.
>
> [10 CFR 54.21(c)]

1.2 Applicability

This instruction is to be used by STARS Plant Aging Management Center of Business (PAM COB) staff and Plant License Renewal Project Staff for identification, screening, evaluation, or disposition of TLAAs in support of each STARS plant's LRA.

The STARS LR Project Manager may designate other individuals to perform checking or review. The Plant LR Project Manager may designate other individuals to perform owner acceptance.

2.0 REFERENCES

1. Title 10, United States Code of Federal Regulations, *Energy,* Part 54 (10 CFR 54), *Requirements for Renewal of Operating Licenses for Nuclear Power Plants.*

2. US NRC NUREG-1800. *Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants.* Rev. 1. September 2005.

3. US NRC NUREG-1801. *Generic Aging Lessons Learned (GALL) Report.* Rev. 1. September 2005.

4. PAM COB Project Instruction PI-1. *Scoping and Screening of Systems, Structures and Components.* Current revision.

5. PAM COB Project Instruction PI-2. *Aging Management Review.* Current revision.

6. PAM COB Desktop Guide DG-1. *License Renewal Data Management Tool Users Manual.* Current revision.

7. Electric Power Research Institute Report EPRI TR-105090. *Guidelines to Implement the License Renewal Technical Requirements of 10CFR54 for Integrated Plant Assessments and Time-Limited Aging Analyses.* Licensed Proprietary Material. MDC-Ogden Environmental and Energy Services, Inc., and Gilbert/Commonwealth, Inc., for EPRI, November, 1995.

   This document was the basis for NEI 95-10 [Ref. 8]. Appendix C incorporates EPRI 12-16424, *Identification of Potential Time-Limited Aging Analyses Inherent in the Common Codes and Standards for Nuclear Power Plants.*

8. Nuclear Energy Institute Report NEI 95-10. *Industry Guideline for Implementing the Requirements of 10 CFR Part 54 – the License Renewal Rule.* Revision 6. Nuclear Energy Institute: June 2005.

9. WCAP 14422-A. W. S. Lapay, C. Y. Yang, and C. Kim. Westinghouse Owners Group and Electric Power Research Institute Generic License Renewal Program Topical Report. *License Renewal Evaluation: Aging Management for Reactor Coolant System Supports.* Revision 2-A. Pittsburgh: Westinghouse Electric Company LLC, December 2000. (Accepted version of WCAP-14422, Revision 2, 4 March 1997). Includes Reference 16.

10. WCAP 14574-A. R. L. Sylvester and M. A. Gray. Westinghouse Owners Group Generic License Renewal Program Topical Report. *License Renewal Evaluation: Aging Management Evaluation for Pressurizers.* Pittsburgh: Westinghouse Electric Company LLC, December 2000. (Accepted version of WCAP-14574, Revision 0, July 1996). Includes Reference 17.

11. WCAP 14575-A. Frank Klanica and Charlie Gay. Westinghouse Owners Group Generic License Renewal Program Topical Report. *Aging Management for Class 1 Piping and Associated Pressure Boundary Components.* Pittsburgh: Westinghouse Electric Company LLC, December 2000. (Accepted version of WCAP-14575, Revision 1, August 1996). Includes Reference 18.

12. WCAP 14577-A. D. R. Forsyth et al. Westinghouse Owners Group Generic License Renewal Program Topical Report. *License Renewal Evaluation: Aging Management for Reactor Internals.* Revision 1-A. Pittsburgh: Westinghouse Electric Company LLC, March 2001. (Accepted version of WCAP-14577, Revision 1, October 2000). Includes Reference 19.

13. WCAP 14756-A. R. F. Condrac and W. S. LaPay (Westinghouse); and Dale Krause and Eric Blocher (Gilbert Commonwealth). Westinghouse Owners Group Generic License Renewal Program Topical Report. *Aging Management Evaluation for the Pressurized Water Reactor Containment Structure.* Pittsburgh: Westinghouse Electric Company, May 2001. (Accepted version of WCAP-14756, Revision 0, December 1996). Includes Reference 20.

14. WCAP 15338-A. Warren Bamford and R. D. Rishel. Westinghouse Owners Group Generic License Renewal Program Topical Report. *A Review of Cracking Associated with Weld Deposited Cladding in Operating PWR Plants.* Pittsburgh: Westinghouse Electric Company LLC, October 2002. (Accepted version of WCAP-15338, March 2001). Includes Reference 21.

15. WCAP 15666-A. P. L. Strauch et al. *Extension of Reactor Coolant Pump Motor Flywheel Examination.* Rev. 1. For the Westinghouse Owners Group (WOG). Pittsburgh: Westinghouse, October 2003. The NRC Safety Evaluation is Reference 22.

16. US NRC Letter. Christopher I. Grimes, Chief, License Renewal and Standardization Branch, Division of Regulatory Improvement Programs, Office of Nuclear Reactor Regulation; to Roger A. Newton, Chairman, Westinghouse

Owners Group (WOG), Wisconsin Electric Power Company. "Acceptance for Referencing of Generic License Renewal Program Topical Report Entitle, *[sic]* 'License Renewal Evaluation: Aging Management for Reactor Coolant System Supports,' WCAP-14422, Revision 2, February 1997." 17 November 2000.

With attached *Final Safety Evaluation by the Office of Nuclear Reactor Regulation Concerning License Renewal Evaluation: Aging Management for Reactor Coolant System Supports, Westinghouse Owners Group Generic Technical Report WCAP-14422, Rev. 2.*

17. US NRC Letter. Grimes (NRC) to Newton (WOG). "Acceptance for Referencing of Generic License Renewal Program Topical Report Entitle, *[sic]* 'License Renewal Evaluation: Aging Management Evaluation for Pressurizers,' WCAP-14574, Revision 0, July 1996." 26 October 2000.

    With attached *Final Safety Evaluation by the Office of Nuclear Reactor Regulation Concerning Westinghouse Owners Group Topical Report WCAP–14574, "License Renewal Evaluation: Aging Management Evaluation for Pressurizers."*

18. US NRC Letter. Grimes (NRC) to Newton (WOG). "Acceptance for Referencing of Generic License Renewal Program Topical Report Entitle, *[sic]* 'License Renewal Evaluation: Aging Management for Class 1 Piping and Associated Pressure Boundary Components,' WCAP-14575, Revision 1, August 1996." 8 November 2000.

    With attached *Final Safety Evaluation by the Office of Nuclear Reactor Regulation Concerning Westinghouse Owners Group Report, WCAP–14575, Revision 1, "License Renewal Evaluation: Aging Management for Class 1 Piping and Associated Pressure Boundary Components," Project No. 686.*

19. US NRC Letter. Grimes (NRC) to Newton (WOG). "Acceptance for Referencing of Generic License Renewal Program Topical Report Entitled, 'License Renewal Evaluation: Aging Management for Reactor Internals,' WCAP-14577, Revision 1, October 2000." 10 February 2001.

    With attached *Final Safety Evaluation by the Office of Nuclear Reactor Regulation of "License Renewal Evaluation: Aging Management for Reactor Internals," Westinghouse Owners Group Life Cycle Management/License Renewal Program Report No. WCAP-14577, Rev. 1.*

20. US NRC Letter. Grimes (NRC) to Newton (WOG). "Acceptance for Referencing of Generic License Renewal Program Topical Report Entitled, 'Aging Management Evaluation for the Pressurized Water Reactor Containment Structure' WCAP-14756, Revision 0, December 1996." 13 April 2001.

With attached *Final Safety Evaluation by the Office of Nuclear Reactor Regulation Concerning Westinghouse Owners Group Generic Technical Report WCAP–14756, Revision 0, December 1996, "Aging Management Evaluation for the Pressurized Water Reactor Containment Structure."*

With attached TER. R. Morante, P. Bezler, and J. Braverman. *Technical Evaluation Report (TER) for Westinghouse Owners Group Generic Technical Report WCAP-14756 Revision 0, December 1996, "Aging Management Evaluation for Pressurized Water Reactor Containment Structure," Project No. 686.* Energy Sciences and Technology Department, Brookhaven National Laboratory, October 2000.

21. US NRC Letter. ~~,~~ Grimes (NRC) to Newton (WOG). "Safety Evaluation of WCAP-15338, 'A Review of Cracking Associated with Weld Deposited Cladding in Operating PWR Plants.'" 15 October 2001.

With attached *Safety Evaluation by the Office of Nuclear Reactor Regulation, Topical Report WCAP–15338, "A Review of Cracking Associated with Weld Deposited Cladding in Operating Pressurized Water Reactor (PWR) Plants," Westinghouse Owners Group.*

22. US NRC Letter. Herbert N. Berkow, Director, Project Directorate IV, Division of Licensing Project Management, Office of Nuclear Reactor Regulation; to Robert H. Bryan, Chairman, Westinghouse Owners Group. "Safety Evaluation of Topical Report WCAP-15666, 'Extension of Reactor Coolant Pump Motor Flywheel Examination' (TAC No. MB2819)." 5 May 2003 [ADAMS Accession No. ML031250595].

With attached *Safety Evaluation by the Office of Nuclear Reactor Regulation, Topical Report WCAP-15666, "Extension of Reactor Coolant Pump Motor Flywheel Examination," Westinghouse Owners Group.*

3.0 DEFINITIONS

3.1 **Aging Management Program (AMP)** – Various plant activities (engineering, operations, or maintenance) used to ensure that the effects of aging will be adequately managed so that the structure or component intended function(s) will be maintained for the period of extended operation.

3.2 **Aging Management Review (AMR)** – An evaluation of aging effects and means of their qualification or management for the period of extended operation, meeting requirements of 10 CFR 54.21(a). AMRs are governed by STARS instruction PI-2. The AMR constitutes the Integrated Plant Assessment (IPA) defined by 10 CFR 54.3(a). The AMR process includes aging evaluations, AMP evaluations and operating experience reviews.

3.3 **Center of Business (COB), Plant Aging Management Center of Business (PAM COB)** – Offices maintained at the Palo Verde Nuclear Generating Station for purposes of managing and performing license renewal and other efforts for the STARS nuclear generating plants.

3.4 **Current Licensing Basis (CLB)** – Documents and commitments on which a plant license is based. See 10 CFR 54.3(a) for a detailed definition. See Attachment 1 for examples of source documents.

3.5 **CLB Primary Sources** – Documents which record the current licensing bases (CLB) as defined by 10 CFR 54.3(a). See Attachment 1 for examples.

3.6 **CLB Secondary and Tertiary Sources** – Documents which record information and analyses necessary to confirm the validity of current licensing basis statements. See Attachment 1 for examples. These are documents that confirm the licensing basis statements in primary CLB sources. Secondary sources may be cited or implied in primary CLB sources or in other secondary sources (thence "tertiary sources"). Secondary sources may be logically necessary to support a conclusion or commitment stated in the CLB sources although not directly cited therein. A citation may therefore not be necessary to establish a secondary or supporting source by inference. A citation may also be insufficient, if the cited secondary source is immaterial to the truth or falsehood of the CLB statement.

3.7 **Disposition (of TLAAs)** – A revision, recalculation, evaluation, argument, or action to demonstrate the validity of a TLAA, or the acceptability of the effect that it analyzes, for the period of extended operation. One of the three dispositions defined by 10 CFR 54.21(c)(1) may be used, or a combination of them. Disposition shall be by a demonstration that

> (i) The analyses remain valid for the period of extended operation;
>
> (ii) The analyses have been projected to the end of the period of extended operation; or
>
> (iii) The effects of aging on the intended function(s) will be adequately managed for the period of extended operation.
>
> [10 CFR 54.21(c)(1)]

A written demonstration in the LRA is sufficient, in the form of a description of (i) the basis for validation of existing analysis, or (ii) of the successful revision of an analysis, or (iii) of citable test results, program documents, and procedures. The calculations, analyses, and program documents must be completed or under a licensing commitment to do so, and are subject to audit.

3.8 **Integrated Plant Assessment (IPA)** – An assessment of effects of nuclear plant aging in support of a license renewal application. The IPA is defined by 10 CFR 54.3(a). For STARS plants the IPA shall be documented in an Aging Management Review (AMR) and supporting position papers.

3.9 **License Renewal Data Management Tool (LRDMT)** - An electronic database used to populate fields of information during the performance, review and approval of scoping/screening, aging management review, and aging management program (AMP) review license renewal activities. This database contains component information necessary to document and evaluate whether systems, structures, and components fall within the scope of 10 CFR 54.4(a)(1) through (3) and to identify those components subject to aging management review; and provides means of documenting other reviews.

3.10 **Plant Aging Management Center of Business (PAM COB)** – See Center of Business (COB), Definition 3.3 above.

3.11 **Plant License Renewal Project Manager (Plant LR Project Manager)** – The project manager assigned by an individual STARS plant organization to manage the license renewal project for that plant.

3.12 **Plant License Renewal Project Staff** – The plant license renewal project manager and Subject Matter Experts (SMEs), or other managers, engineers, data specialists, and support personnel assigned by an individual STARS plant organization to manage and support the license renewal project for that plant.

3.13 **Potential TLAA** – An analysis, evaluation, calculation, or assumption described, cited, or necessary to support the CLB and whose description in a CLB source document would appear, to a qualified reviewer, to be time-dependent and to otherwise have a *potential* to meet all six 10 CFR 54.3(a) criteria.

3.14 **Screening** (of TLAAs) – An evaluation to determine whether a calculation, analysis, or evaluation meets the 10 CFR 54(a) definition of a TLAA.

3.15 **STARS** – Strategic Teaming And Resource Sharing of nuclear operating plants.

3.16 **STARS License Renewal Project Manager (STARS LR Project Manager)** – The project manager assigned to manage license renewal projects for STARS plants from the PAM COB.

3.17 **STARS License Renewal Project Staff** – The STARS LR Project Manager, the TLAA Lead Engineer and any TLAA Evaluators, and other engineers and specialists assigned to work on STARS license renewal projects, and STARS plant utility representatives assigned to PAM COB.

3.18 **STARS PAM COB Manager** – The manager assigned by the STARS plant organizations to manage PAM COB license renewal business.

3.19 **Subject Matter Expert (SME)** – A technical representative responsible for and familiar with a system, structure, component, analysis, program, or other technical issue; and assigned by the individual plant organization to provide support for the plant license renewal project.

3.20 **Time-limited aging analysis (TLAA)** – A TLAA is a calculation, analysis, or evaluation,[1] which meets *all six* of the following defining criteria from 10 CFR 54.3(a):

> *Time-limited aging analyses,* for the purposes of this part [i.e., of 10 CFR 54, the license renewal rule], are those licensee calculations and analyses that:
>
> (1) Involve systems, structures, and components within the scope of license renewal, as delineated in §54.4(a);
>
> (2) Consider the effects of aging;
>
> (3) Involve time-limited assumptions defined by the current operating term, for example, 40 years;
>
> (4) Were determined to be relevant by the licensee in making a safety determination;
>
> (5) Involve conclusions or provide the basis for conclusions related to the capability of the system, structure, and component to perform its intended functions, as delineated in §54.4(b); and
>
> (6) Are contained or incorporated by reference in the CLB.

[10 CFR 54.3(a)]

3.21 **TLAA evaluation –** Work described by this instruction in order to meet the requirements of 10 CFR 54.21(c).

[1] An "assumption" can also be a TLAA (or supported by a TLAA), if it is based on a calculation or analysis.

3.22 **TLAA Evaluator –** A TLAA Lead Engineer, or another project staff engineer assigned to perform TLAA evaluation tasks described in this instruction under the direction of a TLAA Lead Engineer.

3.23 **TLAA Lead Engineer –** A senior engineer assigned primary responsibility for managing and ensuring the performance of the TLAA evaluation activities described in this instruction, excepting those activities to be performed by the plant organization. At least one TLAA Lead Engineer will be assigned for the duration of this task.

3.24 **TLAA validation** – The first of the three *dispositions* defined by 10 CFR 54.21(c)(1). See Definition 3.7 above.

4.0 INSTRUCTIONS

The TLAA review identifies and evaluates those calculations or analyses for structures, systems, and components (SSCs) within the scope of the license renewal rule, whose safety determination depends on a calculation of the cumulative effect of an aging phenomenon, and whose result or conclusion depends on the plant licensed operating period.

The following subtasks through number 4.15 are approximately in order of occurrence, but may be performed in any order which available information and other resources permit.

4.1 Develop a Preliminary Potential TLAA List

The TLAA review will incorporate results of reviews of generic issues and common equipment and commodity types performed under Electric Power Research Institute (EPRI), Nuclear Energy Institute (NEI), Westinghouse and Combustion Engineering PWR Owners Group initiatives (WOG and CEOG), Westinghouse Owners Group Generic License Renewal Program Topical Reports (GTRs, Refs. 9 through 14), those indicated in Tables 4.1-2 and 4.1-3 of the *Standard Review Plan for License Renewal* (the SRP), and those reported in other license renewal applications.

The large number of successful license applications to date and the relatively-limited number of types of TLAAs identified in them provides sufficient experience to permit reliable identification of all TLAAs supporting a given plant license without an exhaustive review of all supporting calculations and analyses. A review by a word search of current licensing basis documents plus the set of design analyses and evaluations expected for a subset of the components and events for a given reactor vendor and plant type, as summarized in the preliminary TLAA list, are sufficient to identify all applicable TLAAs, with a high degree of confidence.

4.1.1 *Organization by SRP-LRA TLAA Categories:* The six categories appearing in major subheads of Chapter 4 of the Standard Review Plan [the SRP, Ref. 2, subheads 4.2 through 4.7] shall be the major topical heads of the potential TLAA list, of the major portion of the TLAA report, and of Chapter 4 of the LRA. All TLAAs not assignable to the first five specific categories shall be organized in a logical fashion under the title of SRP subhead 4.7, "Other Plant-Specific TLAAs."

The rule specifically requires review of the bases of 10 CFR 50.12 license exemptions.

4.1.2 *Preliminary List of Potential Specific TLAAs:* The TLAA Lead Engineer shall construct a preliminary list of potential specific TLAAs whose possible applicability to the plant should be investigated, as a starting point for the table of contents for the TLAA report. The SRP, TLAA reviews or LRAs for other plants, and NRC and industry sources such as References 3, 7, and 8 shall be used to ensure that the list incorporates known potential issues. This list should include all known examples of TLAAs specific to the reactor type, vendor model, and design period; and should similarly omit those clearly not applicable.

4.1.3 These potential TLAA and category descriptions are not fixed or "approved" until the TLAA report is reviewed and approved. The list and TLAA report table of contents will change as licensing basis documents are reviewed and as the potential TLAAs are evaluated.

4.2 Conduct a Readiness Review - Conduct Subject Matter Expert Interviews and Retrieve Preliminary Information

A license renewal readiness review will be conducted for each plant. The readiness review will examine documents and will interview plant and engineering personnel to identify documentation, material, and program conditions that might require additional planning or prerequisite actions, or which suggest actions that could simplify the license renewal process.

4.2.1 As part of the readiness review for each plant, the TLAA Lead Engineer or other designated individual will conduct preliminary information retrievals and interviews with appropriate cognizant staff (Subject Matter Experts, SMEs) at each plant. For each major topic or class of potential TLAAs, the interviews will identify and examine

- *Information systems and sources* available to support the TLAA review process

- *Strengths* in the material condition of structures, systems, and components; and in analyses, programs, and documentation
- *Weaknesses* in the same
- *Potential Plant-unique TLAAs:* Plant-unique analyses, and conditions whose dispositions may have required analyses, which may be TLAAs.

4.2.2 The TLAA Lead Engineer or other designated individual will retrieve any useful documents readily available, and will identify means of retrieving others required.

4.2.3 The TLAA Lead Engineer or other designated individual will complete interview notes and TLAA sections of the Readiness Review Report.

4.3 Revise the Potential TLAA List

4.3.1 *The preliminary list of potential TLAAs will be revised* to add plant-specific TLAAs identified during the readiness review information retrievals and interviews, and to eliminate others not applicable. The revised preliminary list will be issued to the STARS LR Project Manager and to the Plant LR Project Manager for information and comment.

4.3.2 The potential TLAA list will be maintained only as required to produce the TLAA report, that is, until a draft table of contents of the TLAA report is available. It is not a controlled document, nor a deliverable.

4.3.3 The preliminary list of potential TLAAs attached to this instruction (Attachment 3) is for information only.

4.4 Retrieve Current Licensing Basis Information, Confirm Potential TLAAs, Identify Additional Plant-Specific TLAAs

4.4.1 The TLAA Evaluator and STARS License Renewal Project Staff shall use available document retrieval tools, with the help of the plant license renewal staff as needed, to retrieve appropriate licensing basis, design basis, and design documents.

4.4.2 The TLAA Evaluator shall review these documents to confirm whether analyses identified in the potential TLAA list in fact exist for the respective plant, and to discover any additional TLAAs which may be unique to each plant.

Primary licensing basis documents (FSAR or USAR, Tech Specs, SER, SEs, commitments, docketed correspondence, etc.) are most significant and will be reviewed first. If an analysis or evaluation is not "…contained or incorporated by reference in the CLB" it is not a TLAA (10 CFR 54.3(a)(6), "Criterion 6"). Early application of this criterion limits the scope of the subsequent evaluation effort. See Attachment 1 for a typical list of primary ("upper level") and secondary sources of CLB information.

Electronic word searches will be used if possible, and manual searches of the upper-level CLB sources will be used if necessary, to confirm the identification of potential TLAAs. See Attachment 2 for a search list.

4.4.3 The TLAA Evaluator and Plant License Renewal Project Staff shall retrieve 10 CFR 50.12 license exemptions as described in 10 CFR 54.21(c)(2).

4.4.4 The TLAA Evaluator shall review the 10 CFR 50.12 license exemptions for possible TLAAs.

4.4.5 The TLAA Evaluator shall record the results of these reviews in the draft TLAA report and its open items list:

4.4.5.1 Record any additional plant-specific potential TLAAs which are discovered in the review of the CLB. The entries shall describe the issue, including pertinent quotations and citations, and shall cite the sources (see "Bibliography~~Bibliography~~," Paragraph 4.11.7 below).

4.4.5.2 Record the *negative* results of completed searches of CLB documents which indicate that for a particular plant or unit there is no evidence of a CLB for a potential TLAA, and therefore that the potential TLAA fails criterion six and is not a TLAA to the best of the reviewer's knowledge and belief.

4.4.5.3 Record other bases for determining that a potential TLAA either meets all six, or fails any of the six screening criteria (see Definition 3.20 above).

4.4.5.4 Include complete bibliographic information for references. See Paragraph 4.11.7 below.

4.5 Screen Potential TLAAs

The TLAA Evaluator shall

4.5.1 Review each potential TLAA against the six 10 CFR 50.54 criteria (Definition 3.20 above).

4.5.2 Record the results of these reviews in the draft TLAA report, including the basis for the determination.

4.5.3 Place the description and review material of each in the correct section of the draft TLAA report. (The screening basis of those found to not be TLAAs, and which are not mentioned in the Standard Review Plan Table 4.1-2 and Table 4.1-3 [Ref. 2], should be described in a separate Section of the report, apart from the sections which correspond to the LRA.)

4.6 Maintain Information Exchange with Aging Management Reviews and other Evaluations

4.6.1 The TLAA Lead Engineer shall supply any information arising in the course of the TLAA review that may be useful for license renewal aging management reviews (AMRs) and for other evaluations necessary to the license renewal project to the authors of those efforts.

4.6.2 Authors of AMRs and other evaluations necessary to the license renewal project are similarly expected to advise the TLAA Lead Engineer of indications of potential TLAAs as they arise, and to provide supporting information.

4.6.3 The information exchanged will be furnished for the use it may have, "for information only."

4.7 Evaluate and Propose TLAA Dispositions

4.7.1 The TLAA Evaluator shall evaluate TLAAs to determine possible demonstrations of acceptability for the period of extended operation within the three dispositions of 10 CFR 54.21(c)(1).

4.7.2 If the TLAA Evaluator invokes any applicable dispositions approved by NRC safety evaluations of the Westinghouse Owners Group Generic License Renewal Program Topical Reports (GTRs, Refs. 9 through 14),[2] other topicals (e.g., Ref. 15),[3] or other applicable NRC-approved dispositions documented in other sources, he or she shall confirm that no unintended licensing commitments are expressed or implied by invoking these dispositions.

4.7.3 Determining possible dispositions may require reviewing analyses to determine the possibility of validation or revision, and may require investigating existing

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[2] The NRC transmittal letter of each of the safety evaluations for the these GTRs states that

> The staff does not intend to repeat its review of the matters described in the report and found acceptable in the FSER when the report appears as [a] reference in license renewal applications [or "in a … application"], except to ensure that the material presented applies to the specified plant.

These GTR reports are applicable to all units with Westinghouse steam supply systems (all STARS units except Palo Verde), and can be cited in support of their license renewals. Particular applicability will depend on the analysis and conclusions of the specific report, and of the use to be made of them in the TLAA report and LRA. Specific information may also be useful for the Palo Verde Combustion Engineering units.

[3] This Westinghouse Topical is not directly applicable to the Palo Verde reactor coolant pump flywheels.

aging management and surveillance programs and activities. The cooperation of Subject Matter Experts and managers for existing programs and activities which might be affected by aging management dispositions will be necessary. See Section 4.9 below.

4.7.4 The TLAA Evaluator shall record the results of the disposition evaluation of each TLAA and its basis in the draft TLAA report. Draft and tentative evaluations are expected, and shall be marked "DRAFT." Actions to be completed and their assignees or suggested assignees should be described.

4.8 Validate TLAAs

4.8.1 For those TLAAs for which a validation of the existing analysis or calculation is possible, the TLAA Evaluator shall propose a validation in the draft TLAA report.

4.8.2 Validation will usually be possible only for phenomena

- For which an industry position has established a resolution acceptable to the Nuclear Regulatory Commission (Paragraph 4.7.2 above), or
- Which are linear with time and whose effects can therefore be readily extrapolated, within the acceptance criterion or criteria, to a 60-year plant life.

4.8.3 State the acceptance criterion or criteria, describe the basis for the extrapolation or other means of validation, state the expected values of the parameter or parameters at 60 years, and state the conclusion: "The [expected effects] are therefore acceptable for the 60-year extended period of extended operation."

4.9 Support Plant TLAA Revision and Aging Management Disposition Activities

4.9.1 Dispositions which require either revision of the analyses or evaluations (the existing TLAAs), or which require revising procedures or constructing new procedures for aging management activities, must be performed under a 10 CFR 50 Appendix B program. These dispositions must therefore be performed either by the plant organization, or as another task under such a program. This section describes activities by TLAA Evaluators to support these activities.

4.9.2 *Supply an advanced list of and information on possible large-scope TLAA dispositions.* The lists of potential TLAAs for each license will be developed following the readiness review. The TLAA Lead Engineer and Evaluators shall support Plant License Renewal Project staff for purposes of identifying these issues for early assessment and planning. The TLAA Lead Engineers and

Evaluators shall furnish pertinent information and limited written briefs extracted from previous license renewal applications and TLAA evaluations.

4.9.3 *Investigate requirements of the license renewal rule and recommend dispositions.* The TLAA Lead Engineer and Evaluators shall perform an initial evaluation and shall recommend a disposition, supported as needed by interpretations of the license renewal rule, as described in Section 4.7 above.

4.9.4 *Evaluate plant aging management programs (AMPs) used for TLAA dispositions against NUREG-1801 AMP 10-element evaluations.* The TLAA Lead Engineer and Evaluators shall prepare a written evaluation of aging management programs used for TLAA dispositions, but not provided by aging management review authors (AMR authors), using the NUREG-1801 AMP 10-element evaluations [Ref. 3]; and shall include these comparisons in the corresponding License Renewal Data Management Tool (LRDMT) AMP evaluations. AMP evaluations shall be prepared using the guidance provided by Reference 5.

NUREG-1801 AMP 10-element evaluations performed by AMR authors or others may also be cited in support of a TLAA disposition.

4.9.5 *Provide "further evaluations" of aging effects indicated by NUREG-1801 Volume 1.* In an appendix, provide a 9-column tabular listing and "further evaluation" of those aging effects that are identified as TLAAs requiring further evaluation by the NUREG-1801 Volume 1 tables. The "further evaluations" in this 9-column table should be a summary of the required further evaluations or the basis for their omission, and should cite the location within the TLAA report of those further evaluations, or of any additional discussion of the basis for omission.

4.9.6 *Additional consultation and support for TLAA dispositions.* The TLAA Lead Engineer and STARS License Renewal Project Staff shall provide support in addition to the tasks described in this instruction, if authorized.

4.10 Maintain an Open Items List

4.10.1 The TLAA Lead Engineer shall maintain an open items list as part of the draft TLAA report.

4.10.2 The TLAA Lead Engineer shall issue the then-current open items list as part of Revision 0 of the TLAA report, or as a separate deliverable, as the Plant LR Project Manager may direct.

4.10.3 The open items list shall describe the

- Portion of the TLAA report affected
- Analyses, evaluations, conclusions, or dispositions affected or which may be affected
- Technical question, missing documentation, or other issue requiring resolution,

—and if available, the

- Responsible assignee
- Proposed resolution, and
- Expected schedule for resolution.

4.11 Prepare a TLAA Report

Purpose, Form, Content, Development, and Use: The TLAA Lead Engineer and TLAA Evaluators shall prepare a TLAA report for each STARS plant applying for a renewed operating license.

4.11.1 *Title:* Any appropriate title may be used, but for future identification the title should contain

- The plant name
- "License Renewal"
- "Time-Limited Aging Analysis" [or "…Analyses"], and
- "TLAA".

For example

"[Plant Name] License Renewal Time-Limited Aging Analysis (TLAA) Report"

"Review of Time-Limited Aging Analyses (TLAAs) for [Plant Name] License Renewal."

4.11.2 *Purpose - Produce and support LRA Chapter 4 et al:* The report shall contain all information necessary to document

- The results of work performed under this instruction, and
- The basis of Chapter 4 of the License Renewal Application, and of its supporting attachments and appendices.

The TLAA report shall support production of Chapter 4 of the LRA, and necessary supporting LRA appendices, in the most efficient manner possible.~~:~~

4.11.2.1 To meet these purposes the report shall assemble information from other documents and collate and interpret it to determine whether each potential

TLAA calculation, analysis, or evaluation in fact constitutes a TLAA under the 10 CFR 54.3(a) criteria; and shall propose a disposition for each which both meets requirements of the rule and is acceptable to the plant.

4.11.2.2 Text necessary for the LRA shall be clearly denoted or separated, and shall be as close as practical to the format and language of the LRA, to permit ready extraction and production of LRA Chapter 4. Fonts, numbering, etc. need not conform exactly. Tables, figures, and other elements that are time-consuming to reformat should conform more closely.

4.11.2.3 Information in the TLAA report necessary to document the review, but which will not be in the LRA, should be placed in separate sections where practical. For example, the bases for determining that an analysis or evaluation is not a TLAA, or that a design or resolution of an issue is not supported by a TLAA, should be placed in a separate section, except for reasons described in Paragraph 4.11.2.4 below.

4.11.2.4 The LRA (and the LRA sections of the TLAA report) should however include brief discussions of a limited number of potential TLAAs not applicable to the plant in question, in order to document the basis for their exclusion. In particular-

- Those suggested by Standard Review Plan Tables 4.1-2 and 4.1-3, and
- Those whose description in the FSAR or other licensing basis documents appears to indicate a TLAA.

This is to facilitate NRC review of the LRA, and to limit unnecessary requests for additional information (RAIs).

4.11.3 *Format:* The TLAA report shall be prepared in a commercial word processing format, and shall employ automatic section and paragraph numbering and dynamic cross-referencing and citation, to prevent loss of reference integrity as the report is produced and revised. *These dynamic cross references and citations will be stripped from the report, or from an alternate electronic copy of the report, when issued as Revision 0, if so directed by the Plant LR Project Manager.*

4.11.4 *Content:* The TLAA report will ordinarily contain at least Sections 1-9 of the following sample outline. The detailed order may vary, if the requirements of Paragraph 4.1.1 above are met.

Section 8 of the TLAA report will contain or refer to the survey of license exemptions that confirm which, if any are supported by TLAAs. The corresponding section of the LRA will usually be only a brief notice that the survey found none, since 10 CFR 50.12 exemptions supported by a TLAA are not common.

<u>**Example of TLAA Report Contents**</u>

Review and Approval, and Summary of Changes
Table of Contents
Open Items (-until none remain. See Section 4.10 above.)

1.0 Summary of Time-Limited Aging Analyses
- **1.1 Introduction**
- **1.2 Identification of TLAAs**
  - **1.2.1 Methods**
  - **1.2.2 Plant Classification System** (if unique)
- **1.3 Identification of Exemptions**
- **1.4 Summary of Results**
  - **Table 1.4-1: List of TLAAs** (Including disposition type. A summary list for the LRA)

2.0 Reactor Vessel Neutron Embrittlement
- **Neutron Fluence and its Effects** (Introduction - summary of effects, projection of fluence to 60 years, if available)
- **2.1 Upper Shelf Energy and Adjusted Reference Temperature** (USE and ART)
- **2.2 Pressurized Thermal Shock** (PTS)
- **2.3 Pressure-Temperature (P-T) Limits**
- **2.4 Low Temperature Overpressure Protection** (LTOP)

3.0 Metal Fatigue
- **3.1 Fatigue in Class 1 Vessels, Piping, and Components**
- **Fatigue Cycle Counting Aging Management Program** (if applicable)
  - **3.1.1 Reactor Vessel Fatigue Analyses**
  - **….**
  - **3.1.2 (Fatigue analyses of other vessels, as applicable)**
  - **….**
  - **3.1.3 Primary Coolant Piping (or ASME Class 1 Piping) Fatigue Analysis**
  - **….**
  - **3.1.4 ASME III Class 1 HELB Locations Based on CUF** (If not applicable, include a brief description of the exclusion basis.)
  - **3.1.5 Crack Growth and Embrittlement Analyses Supporting Reactor Coolant Loop Leak-Before-Break** (If applicable.)
- **3.2 ASME III Subsection NG Reactor Internals Analysis** (if applicable)
- **3.3 Assumed Thermal Cycle Count for Allowable Secondary Stress Range Reduction Factor in Piping and Components** (B31.1, ASME III Cl. 2 and 3, ASME VIII)
- **3.4 Effects of the Reactor Coolant System Environment on Fatigue Life of Piping and Components (Generic Safety Issue 190)**

4.0 Environmental Qualification of Electrical Components
5.0 Concrete Containment Tendon Prestress (If not applicable, include a brief description of the exclusion basis - "The containment of this plant has no tendons.")
6.0 Containment Liner Plate and Penetration Load Cycles (If not applicable, include a brief description of the exclusion basis.)
7.0 Other Plant-Specific Time-Limited Aging Analyses
8.0 TLAAs Supporting 10 CFR 50.12 Exemptions (If any -not common. Summarized in Section 1.3. If only one, include the brief description in this section title.)
9.0 Bases for Exclusion of Apparent TLAAs (See Paragraph 4.11.2.3 above.)
10.0 References (See Paragraph 4.11.7 below.)
Appendix A: Aging Management Review Further Evaluations

Other Appendices and Attachments, as Required

4.11.5 *Citations are required.* The report shall draw appropriate conclusions and make appropriate recommendations based on information available *from cited sources only.* A qualified reader must be able to determine the source of the information and the basis for the argument and its conclusion.

4.11.6 *Citation of Information from Interviews:* If the cited information relies on the memory of a person or persons, the citation may be in the form of a report of an interview (including telephone calls, e-mails, and notes of meetings or conferences). In that case the absence of other documentation shall be noted, with the basis for concluding that written documentation does not or apparently does not exist or cannot be found. Information from these sources may be recorded in the text alone, or may be filed in the plant record and recorded in the bibliography (Paragraph 4.11.7 below). If recorded only in the text of the TLAA report, a note or footnote should include the source information (medium, names, dates, etc.) in this form:

[1] E-mail [telephone conversation, meeting at …, etc.] from [with] <name>, November 22, 2004. The text is included in the description, above, and no separate record of this e-mail [etc.] was maintained.

4.11.7 *Bibliography (References):*

4.11.7.1 Provide a reference list.

4.11.7.2 Enter each document in plant record if not otherwise available, or enter an open item to ensure that this will be done.

4.11.7.3 Record references in standard bibliographic format approximating that acceptable in journals and publications. (At least document title, revision, date, and source sufficient to permit retrieval; plus document number, author(s), and annotations if useful and pertinent).

4.11.7.4 Each reference entry shall be (1) complete, (2) unique and unambiguous (with necessary identifying number, date, revision, etc.), and (3) available, either publicly or in plant records. Include the NRC Public Document Room ADAMS Accession Number or plant file identifiers, if known. *Entries that do not permit a qualified person to retrieve the document are not acceptable.*

4.11.7.5 *Examples:* See Section 2.0 above, and the following additional examples. Any form approximating these examples is acceptable. If in doubt, consult a style guide or the TLAA Lead Engineer.

Additional Bibliography Examples

1. US NRC Regulatory Guide 1.154. *Format and Content of Plant-Specific Pressurized Thermal Shock Safety Analysis Reports for Pressurized Water Reactors.* January 1987.

2. US NRC Generic Letter 92-01 (GL 92-01). *Reactor Vessel Structural Integrity.* Revision 1, Supplement 1. 19 May 1995.

3. US NRC Letter to file. Jon B. Hopkins, Project Manager, Licensing Branch No. 1, Division of Licensing. "Docket No.: STN 50-482 … Kansas Gas and Electric Company … Wolf Creek Generating Station, Unit 1 … Summary of Meeting Held on February 10, 1982, with Wolf Creek Applicant." 18 February 1982 [WCNOC File No. NL-009].

4. US NRC Letter. Kristine M. Thomas, Project Manager, Project Directorate IV-2, Division of Reactor Projects III/IV, Office of Nuclear Reactor Regulation; to Otto L. Maynard, President and Chief Executive Officer, WCNOC. "Request for Additional Information Regarding Reactor Pressure Vessel Integrity at Wolf Creek Nuclear Generating Station (TAC No. MA0584)." 26 March 1998 [WCNOC File No. 98-00416].

5. Westinghouse Report WCAP-15080. *Evaluation of Pressurized Thermal Shock for Wolf Creek.* Revision 1. September 1998.

6. WCNOC Letter WM 98-0101. Otto L. Maynard, President and Chief Executive Officer; to the US NRC Document Control Desk. "Docket No. 50-482: Response to Request for Additional Information Regarding Reactor Pressure Vessel Integrity (Generic Letter 92-01, Revision 1, Supplement 1) and Submittal of Reactor Vessel Surveillance Capsule Test Results per 10 CFR 50, Appendix H (TAC No. MA0584)." 25 September 1998.

With Attached *Response to NRC Request for Additional Information Regarding Reactor Pressure Vessel Integrity at Wolf Creek.*

7. US NRC Letter. Jack Donohew, Senior Project Manager, Section 2, Project Directorate IV & Decommissioning, Division of Licensing Project Management, Office of Nuclear Reactor Regulation; to Otto L. Maynard, President and Chief Executive Officer, WCNOC. "Generic Letter 92 01, Revision 1, Supplement1, 'Reactor Vessel Structural Integrity,' for Wolf Creek Generating Station (TAC No. MA0584)." 12 July 1999 [WCNOC File No. 99-01086].

Note: In these examples (for Wolf Creek) the NRC documents are available from the WCNOC Licensing Research System, and the NRC ADAMS number was unnecessary.

4.12 TLAA Report Review and Approval, and Revision 0 Issue

4.12.1 *Preliminary Review Workshops:* The TLAA Lead Engineer shall prepare preliminary review materials and conduct preliminary review workshops with the Plant LR Project Manager and Subject Matter Experts (SMEs). The purpose of these workshops is to confirm the TLAA identifications and descriptions, and to confirm or develop the dispositions.

4.12.1.1 *Schedule:* The workshops shall be scheduled to follow the major TLAA identification and screening effort, and the first substantially-complete working draft of the TLAA report incorporating those results.

4.12.1.2 *The number, scope, participants, durations, and locations* of these workshops may vary as needed, and shall be determined by mutual agreement between the Plant LR Project Manager, the STARS LR Project Manager, and the TLAA Lead Engineer. The following will usually be required:

- Neutron Embrittlement (TLAA report Section 2). One or two days.
- Fatigue analyses and fatigue monitoring programs (TLAA report Section 3). Two days.
- Environmental Qualification (TLAA report Section 4). One hour, can be a conference call.

- Containment Tendons and Containment Liner and Penetration Fatigue (TLAA report Sections 5 and 6). One day or less.
- General Review of Plant-Specific TLAAs (TLAA report Section 7). One or two days.

These workshops may beneficially be combined with related AMR workshops. For example the embrittlement and reactor vessel AMR workshops, and the containment and structural AMR workshops may be combined.

4.12.1.3 *Review Materials:* The TLAA Lead Engineer shall prepare or assemble preliminary review materials and distribute them for information in advance of the workshop. Review materials will ordinarily include

- Draft TLAA report, or applicable portions of it
- Draft NUREG-1801AMP 10-element review of applicable aging management programs (See Paragraph 4.9.4 above)
- Open Items List, or applicable portions of it
- Supporting position papers, if any
- Other supporting materials not otherwise available to the plant staff.

4.12.2 *Information Exchange:* The TLAA Lead Engineer will maintain informal contact with SMEs as necessary, and will copy the Plant LR Project Manager and the STARS LR Project Manager with any communications between them.

This activity may continue through issue of Revision 0, Paragraph 4.12.6 below.

4.12.3 *Issue the draft TLAA report for STARS project review.* The TLAA Lead Engineer shall issue a working draft of the TLAA report for STARS management and STARS License Renewal Project Staff review. The TLAA Lead Engineer shall revise the TLAA report draft to incorporate STARS project review comments. The STARS LR Project Manager shall identify necessary corrections and authorize release for review by the Plant License Renewal Project Staff and SMEs.

4.12.4 *Issue the draft TLAA report for plant license renewal project review.* The TLAA Lead Engineer shall issue a draft revision of the TLAA report to the Plant LR Project Manager, designated Plant License Renewal Project Staff, and responsible plant SMEs, for review and comment, in preparation for the following review meeting for Revision 0.

Comments will be requested a minimum of five working days in advance of the meeting, but will be received and incorporated throughout the review meeting.

4.12.5 *Review Meeting for Revision 0:* The TLAA Lead Engineer will conduct a TLAA report review working meeting with responsible plant SMEs, at the plant or other location of convenience, to

- Confirm the results of the TLAA identifications
- Confirm the acceptability of the proposed TLAA dispositions
- Confirm open items completed to that date
- Identify action items for closure of remaining open items
- Identify action items for further disposition evaluations, and for execution of dispositions requiring engineering and modification actions, and
- Identify and confirm responsible parties for these action items.

4.12.6 *Issue TLAA report Revision 0 (et seq.).*

4.12.6.1 The TLAA Lead Engineer shall incorporate results of the review meeting, and shall issue Revision 0 to the STARS LR Project Manager, who shall assign a STARS License Renewal Project Staff reviewer.

4.12.6.2 The assigned reviewer shall review Revision 0 as directed by the STARS LR Project Manager, obtain necessary corrections and clarifications from the TLAA Lead Engineer, sign the report as reviewer, and submit it to the STARS LR Project Manager for approval.

4.12.6.3 The STARS LR Project Manager shall review and approve the report, shall obtain any additional necessary corrections and clarifications, and shall submit the report to the Plant LR Project Manager for final approval and use.

4.13 TLAA Report Revision

The TLAA report may be revised at the direction of the Plant LR Project Manager as described from Paragraph 4.12.6 above, if authorized.

4.14 Draft License Renewal Application Chapter 4 and Supporting Appendices

4.14.1 The TLAA Lead Engineer shall extract the LRA material and references from the TLAA report, and from them shall draft Chapter 4 of the LRA, and supporting TLAA elements of LRA Appendices, specifically, of

- Appendix A, "…Safety Analysis Report Supplement"
- Appendix B, "Aging Management Programs"
- Appendix D, "Technical Specification Changes"
- Nine-column reviews of aging effects requiring further evaluations for TLAAs (Paragraph 4.9.5 above).

4.14.2 These drafts will be issued for project use in developing the LRA. The LRA development, review, approval, and submittal are controlled by other STARS project instructions.

4.14.3 The TLAA Lead Engineer and Evaluators shall enter TLAA information into the LRDMT data base tables to support generation of the LRA Chapter 3 summary table descriptions of TLAAs, of aging management review "further evaluations," NUREG-1801 "consistency reviews;" and determination of the applicability of standard notes, of the relation of the aging management review to the TLAA review, and of the demarcations between these reviews [Refs. 5 and 6].

4.15 Post-submittal Licensing Support

The TLAA Lead Engineer and STARS license renewal staff will assist each STARS plant organization in developing written responses to requests for additional information (RAIs) based on the work described in this instruction, including support at NRC meetings if required.

4.16 Records

4.16.1 The TLAA report, and its open items list, if separate, will be the only record or records produced specifically under this instruction.

4.16.2 Entries of AMP reviews and tabular data into the LRDMT (4.9.4 and 4.14.3 above) are controlled by other STARS project instructions and guides [Refs. 4, 5, and 6].

4.16.3 The Plant LR Project Manager is responsible for posting the report and open items list to the individual STARs plant record system.

4.17 Quality Assurance

This work is governed by this instruction and by other instructions and procedures of the STARS License Renewal Project. It is not governed by 10 CFR 50 Appendix B.

5.0 SUPPORT REQUIRED FROM PLANT ORGANIZATIONS

5.1 Each plant organization shall appoint a Plant LR Project Manager and Plant License Renewal Project Staff sufficient for the effort required.

5.2 Each plant organization shall identify appropriate Subject Matter Experts, program managers, and engineering managers, and shall make them available for purposes described in this instruction.

5.3 If the plant organization develops TLAA dispositions or other inputs for the TLAA report or LRA (see Paragraph 4.9.1 above), the plant shall supply required descriptive text and references for inclusion in the TLAA report and LRA.

6.0 CONFLICTS

Conflicts between this instruction and any other STARS license renewal project instruction or procedure shall be identified to the STARS LR Project Manager for resolution.

Attachment 1: Typical Primary and Secondary Sources for the Current Licensing Basis

Primary (upper-level) Sources:

1. FSAR, USAR, or UFSAR - [Updated] [Final] Safety Analysis Report
2. Power Uprate License Submittal (if any)
3. Pressure-Temperature Limits Report (PTLR)
4. Operating License and License Conditions
5. Fire Protection Evaluation Report
6. Quality Assurance Program
7. Offsite Dose Calculation Manual (or equivalent)
8. Technical Specifications
9. Technical Requirements Manual (if separate from Technical Specifications)
10. US NRC Orders and Order Index
11. US NRC Safety Evaluation Report (SER)
12. US NRC Safety Evaluations (SEs) and Index
13. US NRC Correspondence and Index
14. Plant Licensing Correspondence and Index
15. Plant Licensing Commitments and Index or Database

Possible Secondary and Tertiary (supporting) Sources:

16. 10 CFR 50.54f licensing basis review data base (if any).
17. Environment Qualification Binders (Work Packages, etc.)
18. Environmental Qualification Component Database
19. Environmental Qualification Cable Database
20. Preservice and ISI reports (ASME XI Summaries of Reportable Indications) and Index or Database
21. Plant electronic work control system or component database (for operations & maintenance history)
22. Corrective Action Program dispositions of conditions adverse to quality[4]
23. Design Basis Documents
24. Design Basis Document Data Base
25. P&IDs, single lines, and structural drawings
26. Piping, mechanical equipment, structural, and instrumentation specifications (for cited design codes and required analysis methods and analysis inputs)
27. Design Change Packages (or equivalent)
28. Vendor manuals
29. Vendor drawings
30. Piping and vessel code calculations and calculation indexes
31. Piping and vessel code calculation summaries (if any exist)
32. System design calculations and calculation indexes

[4] Only if cited or traced as a supporting analysis from a licensing basis document. Usually not required.

33. Component design calculations[5]
34. Engineering procedures
35. ISI and IST procedures
36. Program procedures
37. Master Parts List (or equivalent)
38. Controlled Document List Database
39. Power Uprate Task Reports
40. Other major modification reports and evaluations, e.g., steam generator replacement.

[5] May need to be requested from the vendor, if not available at the plant document center.

Attachment 2: Sample Key Words for TLAA Source Document Searches

This list was developed from a review of EPRI TR-105090 and its Table 4.1-4 [Ref. 7], from preliminary TLAA lists, and from previous experience. Note that in practice the compound terms will be discovered on a search of single words, which reduces the required search list to those in boldface.

- **40**-year
- **50.12**
- **aging**
- **allowance**
- **alloy 600**
- **analysis***
- **bellows**
- **Boraflex**
- **break**
- **brittle**
- brittle fracture
- **Charpy**
- **Class 1**
- **CMMA**
- component life
- **corrosion**
- corrosion allowance
- **crack** growth
- **creep**
- **cycle**(s)
- cycles /
- cycles per
- cycles/
- **degradation**
- design life
- **ductility**
- effective **full power** year(s)
- **EFPY**
- **Environmental** qualification (EQ)
- **embrittlement**
- **EQ**
- equipment life
- **erosion**
- erosion allowance
- **exemption**
- **expansion** joint
- expected life
- **fatigue**
- fatigue analysis
- **fluence**
- **forty** year(s)
- **fracture**
- fracture mechanics
- fracture toughness
- **growth**
- **hydrotest**
- hydrotest cycles
- **IGSC**(C)
- **intergranular** stress corrosion cracking
- **license***
- license(d) life
- license period
- license term
- **life**
- life cycle
- life expectancy
- life of
- life-cycle
- **lifetime**
- **limit***
- load cycles
- **LTOP**
- **NDT**
- NDTT
- **nil-ductility** transition temperature
- operating cycles
- **period**
- plant life
- pressure cycles
- pressure-temperature cycles
- **pressurized thermal shock**
- **PTS**
- **PWSCC**
- qualified life
- **rate***
- **relaxation**
- **settlement**
- **snubber**
- **starts**
- **stratification**
- temperature cycles
- tendon relaxation
- **term**
- term of the license
- thermal cycles
- **time***
- **toughness**
- **under clad**
- **underclad**
- **under-clad**
- **upper-shelf** energy
- **USE**
- **usage** factor
- **vibration**
- **wastage**
- **wear**
- **year**(s)

*These terms may be too general to produce useful results alone, that is, may produce too many "hits." In that case searches for useful modifiers, elsewhere in this list, or for these terms in proximity to useful modifiers, should discover the instances of interest.

Attachment 3: Potential TLAA List

***Note:* This list is for information only.**

The following list was collected from prior pressurized water reactor license renewal applications (LRAs).

Major heads are from the NUREG-1800 Standard Review Plan, numbers correspond to the 0 - 6 categories of the Standard Review Plan.

Sections 2 and 6 include descriptions of possible TLAAs whose applicability or lack of it at the specific unit must be confirmed.

<u>TLAA Description</u>

0. Exemption Requests under 10 CFR 50.12

0.1 Analyses in Support of 10 CFR 50.12 Exemptions. (There may be no TLAAs. The exemptions must be examined.)

1. Reactor Vessel Neutron Embrittlement

Neutron Fluence, and its Effects

1.1 Limiting-Material Upper Shelf Energy and Adjusted Reference Temperature. (USE and ART)

1.2 PTS (Pressurized Thermal Shock).

1.3 P-T (Pressure-Temperature) Curves.

1.4 LTOP (Low-Temperature Overpressure Protection).

2. Metal Fatigue

2.1 RPV, nozzles, studs, CRDM or CEDM housings, etc.

2.2 Reactor Coolant Pump Pressure Boundary

2.3 Pressurizer and nozzles

2.4 Steam Generator ASME III Class 1 and nozzles

2.5 ASME III Class 1 Valves

2.6 ASME III Class 1 Piping and piping nozzles

2.7 IEB 88-08 Thermal Cycling at Normally-Closed Interface Valves, etc. (if applicable)

2.8 IEB 88-11 Thermal Cycling and Stratification - Pressurizer Surge Line, etc.

2.9 High Energy Line Break (HELB) Postulation Based on Fatigue Cumulative Usage Factor

2.10 Fatigue Crack Growth and CASS Embrittlement Analyses in Support of Leak-Before-Break (LBB) in the Main Reactor Coolant Loops (if applicable)

2.11 ASME III Subsection NG Thermal and High-Cycle Fatigue in Reactor Vessel Internals (—if applicable, depends on code design edition and addendum. For Westinghouse units, this may also include Westinghouse Bulletin TB-03-2 core power and design cycle limits for evaluation of core baffle-to-former bolt design.)

2.12 Environmentally-Assisted Fatigue of NUREG 6260 Locations (Generic Safety Issue 190)

2.13 Assumed Thermal Cycle Count for Allowable Secondary Stress Range Reduction Factor in ASME/ANSI B31.1, and Class 2 and 3 Piping

Possible additional plant-specific fatigue TLAAs:

- ASME III Class 1 Pipe Support Allowable Cycles (1986 or later code editions and addenda)
- Fatigue Design Under ASME Section III Class 2 or Section VIII Division 2 Alternative Rules
- Fatigue Design of Hangers and Supports of Large Piping Designed to ASME/ANSI B31.1 or AWS D1.1, or of Safety Class Structures Designed to AWS D1.1 (not common)
- Penetration and Piping Bellows and Expansion Joint Fatigue Analysis or Design Cycles
- Fatigue Analyses in Support of Containment Penetration Break Exclusion Regions. (Not common. Most designs base break exclusion regions on ASME III Class 2 stress limit criteria, which are not time-dependent.)
- Fatigue Failures of Polar Crane Rail Clamp Plate Studs. (Known to have occurred at two plants, but disposition has not been supported by a TLAA at them.)
- Fatigue Analyses of Specific Component Failures, Designs, or ISI Flaw Indications
- High-Cycle Fatigue Evaluations of Vibration Effects

3. Environmental Qualification of Electrical Equipment (EQ)

3.1 Environmental Qualification of Electrical Equipment

4. Loss of Prestress in Concrete Containment Tendons

4.1 Loss of Prestress in Concrete Containment Tendons

5. Fatigue of the Containment Liner and Penetrations

5.1 Design of the ASME III Class MC Containment Liner for Diurnal, Annual, and Startup-Shutdown Thermal Cycles (if applicable)

5.2 Design Cycles for the Main Steam Line Penetrations (may also apply to other penetrations, but not common for others in PWRs)

6. Other Plant-Specific TLAAs

6.1 Polar and Fuel Building Cask Handling Crane Load Cycle Limits under the CMAA-70 Design Standard (possibly also of the refueling machine or other lifting machinery).

6.2 Fatigue Crack Growth and Corrosion Analyses in Support of Alloy 600 Nozzle Repairs

6.3 Fatigue Crack Growth in Reactor Coolant Pump Flywheels. (Not commonly a TLAA, most support only an inspection interval. Treated here even if not a TLAA because specifically noted in NUREG 1800 Table 4.3-3.)

6.4 Reactor Vessel Underclad Crack Growth Analysis (—if applicable. Westinghouse WCAP 15338-A or 15666 [Refs. 14 and 15] may be invoked in support of disposition of underclad indications in Westinghouse vessels. Treated here even if not a TLAA because specifically noted in NUREG 1800 Table 4.3-3.)

Possible additional plant-specific TLAAs:

- Metal Corrosion Allowances for Piping and Vessels
- Thermal Embrittlement of Cast Austenitic Stainless Steel. (CASS - including reactor coolant pump welded casing Code Case N-481 inspection relief, if applicable.
- Westinghouse RPV Instrumentation Thimble Tube Wear
- Main Steam Isolation Valve Operating Cycles
- Probabalistic Failure Assessments Dependent on the Design Lifetime. (These are not commonly TLAAs. Most such merely establish an inspection interval.)
- Silting of the Ultimate Heat Sink
- Foundation Subsoil Post-Excavation Heave and Design Lifetime Resettlement

Diablo Canyon License Renewal Feasibility Study

TR-10DC
Thermal Insulation
License Renewal Feasibility Study Position Paper

Revision 1~~0~~

~~December~~ January 2~~8~~3, 20~~10~~07

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Thermal Insulation License Renewal Feasibility Study Position Paper
Diablo Canyon Power Plant

Approval Page

Revision	Prepared by:	Reviewed by:	Approved by:	Owner Acceptance
0	Michelle Albright	Eric Blocher	Eric Blocher	--
Date	Nov. 11, 2007	Nov. 30, 2007	Dec 23, 2007	--
1	Stan Shepherd	David Lipinski	David Kunsemiller	Philippe Soenen
Date	January 28, 2010	January 28, 2010	January 28, 2010	February 5, 2010

~~**Open Items:**~~

~~1.Identify the insulation that was installed to maintain Environmental Qualification of LT-503.~~

~~2.Update the operating experience review to include 10 years of DCPP insulation operating experience.~~

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REVISION SUMMARY

Revision	Required Changes to Achieve Revision	Date
0	Initial Issue	Dec. 23, 2007
1	Incorporated PCTF # 68 which incorporated resolutions to the two open items that were on the Approval page, and revised Table 1. Added additional information immediately after Table 1 to explain why the reactor vessel thermal insulation and the thermal barrier for	January 28, 2010

	LT-503 are not in scope of LR, per DCPP request. Also, revised Appendix A to clarify the aging effect of stainless steel stress corrosion cracking. Also, made miscellaneous editorial changes.	

TABLE OF CONTENTS

1. PURPOSE

The purpose of this License Renewal Feasibility Study position paper is to evaluate thermal insulation such as that on piping and mechanical components for Diablo Canyon Power Plant (DCPP) for license renewal in accordance with the License Renewal Rule, 10 CFR 54 (Reference 1). This report does not evaluate electrical insulation or fire barrier insulation/fire wraps that are evaluated separately in the electrical and structural aging management review reports. This paper will determine if thermal insulation on mechanical components requires aging management program for the period of extended operation.

2. BACKGROUND

The inclusion of thermal insulation as a part of the license renewal review process has been evolving with industry and NRC experience.

Due to the lack of industry guidance, thermal insulation scoping and aging evaluation guidance resides primarily in how previous applicants responded to Nuclear Regulatory Commission (NRC) staff questions or otherwise addressed thermal insulation in their applications. Based on the review of recent NRC Requests for Additional Information (RAIs), the current NRC position is that thermal insulation is typically passive and long-lived and, therefore, if it also serves an intended function, then it meets the criteria for inclusion within the scope of license renewal. Each license renewal applicant (LRA) has been required to address thermal insulation scoping and, if applicable, aging management review. The key is whether or not an applicant takes credit for thermal insulation in its current licensing bases (CLB).

In some cases, the NRC has asked license renewal applicants to justify why they excluded specific thermal insulation from the applications. In response to the RAIs, some applicants indicated that thermal insulation did not perform an intended function and, therefore, was not within the scope of license renewal as defined by the criteria set forth in 10 CFR 54. These positions were concurred in the Safety Evaluation Reports (SERs).

For the identification of aging effects, some license renewal reviews have concluded that insulation has no aging effects requiring management and provided operating experience for further justification. A few applicants identified some insulation types that would experience aging effects requiring management, especially when in a wetted environment.

Note that for determining the intended function, Table 2.3-1 of the Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants (SRP) (Reference 4) mentions insulation in an example. It is consistent with the NUREG-1723 (Reference 7) and NUREG-1743 (Reference 8) positions with the following statement about thermal insulation on the boron injection tank:

> "The temperature is high enough that insulation is not necessary to prevent boron precipitation. The plant technical specifications require periodic verification of the tank temperature. Thus the insulation is not relied upon to ensure the function of the emergency system and is not within the scope of license renewal."

It is important to note that ECCS sump clogging issues do not relate to aging and, therefore, are not included in the evaluation of thermal insulation for license renewal. This is a CLB issue that will be addressed under the response to Generic Letter 2004-02: Potential Impact of Debris Blockage on Emergency Recirculation During Design Basis Accidents at Pressurized Water Reactors (Reference 2) and GSI-191: Assessment of Debris Accumulation on PWR Sump Performance (Reference 39).

3. REVIEW OF INDUSTRY DOCUMENTATION AND OTHER APPLICATIONS

The following sections summarize the review of license renewal applications and license renewal SERs.

3.1 Plants With Thermal Insulation Not In Scope

1. Calvert Cliffs LRA and SER (NUREG-1705-Reference 6)

   "….NRC question No. 5.2.8 requested that the applicant specify whether the storage tank and pipe insulation material within the CVCS was within the scope of license renewal and subject to an AMR, and if not, to justify excluding these components from the renewal scope. In response, the applicant stated that the insulation performs none of the intended functions listed in Appendix A to the LRA and, as such is not within the scope of license renewal."

2. Oconee LRA and SER (NUREG-1723-Reference 7)

   "….As a result of monitoring and maintaining the TS temperature limits, any heater failure or excessive heat loss from these tanks and pipes can be detected in time, and corrective actions can be taken to maintain the required boron concentration. The insulation, therefore, need not be within the scope of license renewal, and is not subject to an AMR."

3. ANO-1 LRA and SER (NUREG-1743 -Reference 8)

   "….As a result of this TS requirement, the applicant will have to take corrective actions if the water temperature falls below 40^0F (which is well above the boron precipitation temperature) for any reason, including from the degradation of insulation, age-related or otherwise. The applicant, therefore, concludes that the insulation material of the tank and piping is not required to support any system function that is required to satisfy the criteria of 10 CFR 54.4(a) during or following any DBE."

4. Turkey Point Nuclear Plant LRA and SER (NUREG 1759- Reference 9)

   The Turkey Point application identified insulation in safety injection and CVCS system subsections. The review identified that the thermal insulation was not in the scope of license renewal. An example of this from the LRA is provided below. The SER did not address the scoping of thermal insulations.

> "Insulation is not within the scope of license renewal for the safety injection system because the system does not contain boric acid solutions at concentrations that require heat tracing, tank heaters, and/or insulation to prevent precipitation. "

5. North Anna Units 1 and 2 and Surry Power Station, Units 1 and 2 LRA and SER (NUREG-1766-Reference 10)

   A review of the thermal insulation was performed and documented in a position paper. The review has concluded that no thermal insulation needs to be included within the scope of license renewal.

   This position paper was identified by number and title (LR-1907/2907 "Screening of Thermal Insulation") in the SER and the position that no thermal insulation needs to be included within the scope of license renewal was accepted in the SER.

6. St. Lucie LRA and SER (NUREG 1779-Reference 11)

   The St Lucie application was similar to the Turkey Point application. It reviewed insulation in several system subsections. The review identified that the thermal insulation was not in the scope of license renewal.

   The SER also provides the following additional details:

   > "….By letter dated October 3, 2002, the applicant responded that thermal insulation is not within the scope of license renewal because it does not perform or support any license renewal intended functions that satisfy the scoping criteria of 10 CFR 54.4(a). Environmental temperature qualification of in-containment components is maintained through temperature monitoring and the Units 1 and 2 technical specifications. …… On the basis that insulation does not perform or support any intended function meeting the criteria of 10 CFR 54.4(a), the staff finds the applicant's response to be acceptable. The staff agrees with the applicant that insulation described above should not be included in the scope of license renewal and is not subject to an AMR for Units 1 and 2."

7. Fort Calhoun LRA and SER (NUREG 1782-Reference 12)

   Thermal insulation was identified as utilized to control concrete temperature as follows in LRA**:**

   > "The maximum indoor plant temperature is 120°F inside the main area of containment. This is below the temperature limit of 150°F. Per USAR Section 5.5.4, sleeve radiation fins and thermal sleeves (in conjunction with pipe insulation) are used to limit maximum temperature at the containment penetration sleeves to 150°F under operating conditions."

The Fort Calhoun application and SER did not specifically address whether thermal insulation is in scope of license renewal or not.

8. McGuire Units 1 and 2 and Catawba Units 1 and 2 LRA and SER (NUREG 1772-Reference 13)

   The McGuire Units 1 and 2 and Catawba Units 1 and 2 LRA and SER did not review thermal insulation on mechanical components.

9. R. E. Ginna Nuclear Power Plant LRA and SER (NUREG 1786- Reference 15)

   The Ginna LRA identified that only the containment liner insulation was in the scope of license renewal. No mechanical component thermal insulation was included in the scope of license renewal. This was not found to be disputed in the SER.

3.2 Plants With Thermal Insulation In Scope and No Aging Effects Identified

1. H. B. Robinson LRA and SER (NUREG 1785-Reference 14)

   The H. B. Robinson LRA and SER identified the reactor vessel and certain piping insulation as required to protect the containment concrete. The review concluded an AMP was not required for the mechanical insulation. The following is from the SER:

   > "The containment penetration insulation commodities are identified as high density penetration insulation (BTU-BLOCK Flexible by Manville) and fiberglass blankets for the main steam lines, and ceramic fiber insulation for the steam generator blowdown lines. The subject insulation is located in the containment air environment not subject to boric acid leaks. No aging effects have been identified based on review of RNP operating experience, and based on the protective location of the subject insulation (inside penetrations), no mechanical degradation is expected. Therefore, no aging effects are identified that require management and an AMP is not required."

2. Arkansas Nuclear One Unit 2 (ANO-2) LRA and SER (NUREG-1828-Reference 20)

   The ANO-2 application was completed similar to the ANO-1 application and did not review insulation as a part of the LRA except to identify the RCS insulation was free of contaminants. During the NRC review of the LRA, there were several RAIs associated with insulation. The responses indicated that some insulation may be considered to have a function, but there were no aging effects requiring management. The following is from the SER:

   > "In a letter dated September 15, 2004, the applicant stated that thermal insulation around hot piping penetrations is included in the scope of license renewal for ANO-2. The applicant performed an aging management review of the insulation. Based on the consideration of the material and environment, its protected location, and operating experience, there are no aging effects requiring management for the insulation around

hot piping penetrations. The staff considers its concern described in RAI 2.4-2 resolved."

3. D. C. Cook Units 1 and 2 LRA and SER (NUREG-1831-Reference 21)

   The D. C. Cook application was completed similar to the ANO-1 application and did not review insulation except to identify the RCS insulation was free of contaminants in accordance with WCAP-14575-A. During the NRC review of the LRA, there were several RAIs associated with insulation. The responses identified some insulation may be considered to have a function, but there were no aging effects requiring management. The following is from the SER:

   > " ….. I&M agrees to include the insulation on hot containment piping penetrations in the scope of license renewal. The intended function that was applied to the insulation is to prevent excessive heat transmission to the containment concrete surrounding the piping penetrations. The insulation is encapsulated with stainless steel jacketing in the annulus between the penetration piping and the penetration sleeve. There are no applicable aging effects for insulation in the indoor air environment. A review of CNP operating experience for the past five years verified that the plant has not experienced aging-related degradation of piping insulation in dry indoor environments. Therefore, based upon the material, environment, and operating experience, the insulation is not expected to degrade, and an AMP is not required."

4. Millstone Nuclear Power Station Units 2 and 3 LRA and SER (NUREG-1838-Reference 23)

   The Millstone application did not specifically review thermal insulation on mechanical components. During the NRC review of the LRA, there were several RAIs associated with insulation. The responses identified some insulation may be considered to have a function, but there were no aging effects requiring management. The following is from the SER:

   > "Based on its review, the staff finds the applicant's response to RAI 2.3.3.44-2B acceptable, ….The ability of the system's temperature monitoring instrumentation to localize a low temperature along the length of the piping would allow differentiation between thermal insulation or heat-trace circuit problems. …..appropriate repair would be made before loss of system-level intended function would occur. Therefore, the staff's concern described in RAI 2.3.3.44-2B is resolved."

   > "…. Since the thermal insulation associated with containment piping penetrations functions to limit the heat transferred to the surrounding concrete, similar to the piping penetration cooling systems that are within the scope of license renewal, Dominion will conservatively also include the thermal insulation within the scope of license renewal. The intended function applied to the insulation is to prevent excessive heat transmission to the containment concrete surrounding the piping penetrations….. Based on the aging management review performed for the fiberglass, asbestos, and calcium silicate piping penetration thermal insulation, there are no applicable aging effects in the indoor air environment and no aging management program is required. …. Based on its review, the staff finds the applicant's revised response to RAI 2.4-3

acceptable because the applicant has included the subject thermal insulation within the scope of license renewal."

5. Point Beach Nuclear Plant LRA and SER (NUREG-1839-Reference 24)

   The Point Beach Nuclear Plant LRA identified the insulation for several containment penetrations (Main Steam and Main Feedwater) as in the scope of license renewal. This insulation was not exposed to wetting and the application stated there were no aging effects requiring management. In response to RAI 2.4-3, Point Beach indicated:

   > "….The review identified only one location where thermal insulation is within the scope of license renewal. Insulation is installed on the main steam and main feedwater containment penetrations, and is needed to maintain steady-state concrete temperatures less than 150 degrees F. This insulation is enclosed in the annulus and is not subject to wetting, and there are no plausible aging effects that could warrant aging management."

6. Brunswick Steam Electric Plant LRA and SER (NUREG-1856-Reference 25)

   The Brunswick Steam Electric Plant LRA identified the insulation for Containment hot penetrations, Control Building HVAC, RCIC Room piping, HPCI Room piping and RHR Rooms piping to be included in the scope of license renewal because they are credited in room cooler evaluations. The application stated there were no aging effects requiring management for thermal insulation in an indoor air environment.

7. Monticello Nuclear Generating Plant LRA and SER (NUREG-1865-Reference 26)

   The Monticello Nuclear Generating Plant LRA identified the insulation for HPCI Room piping and RHR Heat Exchanger to be included in the scope of license renewal because they are credited in room heat-up evaluations. The application stated there were no aging effects requiring management for thermal insulation in an indoor air environment.

8. Palisades Nuclear Generating Plant LRA and SER (NUREG-1871-Reference 29)

   Palisades reviewed the current licensing basis and determined that only a small portion of the thermal insulation is in scope for license renewal. They are the insulation at (1) the main feedwater and main steam penetrations that has the environmental control intended function to limit the adjacent concrete temperatures to less than 179F; (2) the stainless steel mirror insulation on the reactor vessel supplied as part of the seismically qualified NSSS system for their spatial impact on safety related components, and (3) Auxiliary Feedwater (AFW) steam supply and exhaust piping in the steam-driven AFW pump room is not subject to any aging effects requiring management.

9. Oyster Creek Nuclear Generating Plant LRA and SER (Reference 30)

Hot piping and component insulation located inside structures in the scope of license renewal; excluding Miscellaneous Yard structures, is in the scope of license renewal under 10 CFR 54.4 (a)(2). All insulation at Oyster Creek is considered non-safety related. Cold piping and component insulation does not perform an intended function and is not included in the scope of license renewal. Also, hot piping and component insulation located inside structures that are not in scope of license renewal, or in Miscellaneous Yard structures, is not in the scope of license renewal since failure of this insulation will not impact an intended safety related function. Oyster Creek further determined that insulation is not subject to any aging effects requiring management.

10. Wolf Creek Generating Station LRA (Reference 34)

    Wolf Creek reviewed the current licensing basis and determined that only a small portion of thermal insulation is in the scope of license renewal. All 10 CFR 54.4 (a)(1) insulation was included in the scope of license renewal. The systems in scope included the Emergency Diesel Generator exhaust penetration, ESF pump rooms, auxiliary feedwater pump rooms, and containment penetrations for Steam Generator Blowdown, CVCS, Feedwater and Main Steam. 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 WCGS plant specific operating experience, it was determined that for stainless steel insulation, closed cell foam, quilted fiberglass insulation, calcium silicate and insulation jacketing in non-aggressive environments, there were no aging effects requiring management.

11. Palo Verde Nuclear Generating Station Thermal Insulation License Renewal Position Paper (TR-10PV) (Reference 35)

    The in-scope thermal insulation that support a function in scope of license renewal is the insulation that is credited with minimizing ESF Pump Room and the EDG Room exhaust penetration heat loading and thermal insulation on the main steam and feedwater lines to prevent high temperature degradation to concrete at the containment penetration. The in-scope thermal insulation is located in areas with non-aggressive environments (meaning the insulation is not exposed to contaminants). The review concluded this insulation does not have any aging effects requiring management.

12. Pilgrim Nuclear Power Station LRA and SER (Reference 36)

    All indoor insulation was included in the scope of license renewal under 10 CFR 54.4 (a)(2). The AMR revealed that "loss of insulating characteristics due to insulation degradation is not an aging effect requiring management for insulation material. Insulation products that are protected from weather do not experience aging effects that would significantly degrade their ability to insulate as designed."

13. Vermont Yankee Nuclear Power Station LRA and Draft SER (Reference 37)

Vermont took the same insulation stance and utilized the same LRA language as Pilgrim Nuclear Power Station. The draft SER currently includes no RAIs or additional insulation information not addressed in the LRA.

14. James A. Fitzpatrick Nuclear Power Plant LRA and Draft SER (Reference 38)

Fitzpatrick took the same insulation stance and utilized the same LRA language as Pilgrim and Vermont Yankee Nuclear Power Stations. In the draft SER, Section 2.4.4.2, Fitzpatrick demonstrated (and the NRC accepted) that 'support for criterion (a)(1) equipment' need not be listed as a separate intended function for insulation.

3.3 Plants With Thermal Insulation In Scope and Requiring Aging Management

1. Edwin Hatch LRA and SER (NUREG-1803-Reference 27)

The Edwin Hatch application identified insulation in selected areas as in the scope of license renewal. Aging effects were then determined assuming a wetted environment and included damage due to water intrusion and loss of material on the metallic insulation jackets. Other aging effects such as thermal fatigue of the jacket, compaction and settling, material separation, and "thermal effects" were also identified as possible aging effects requiring management. A new program Equipment and Piping Insulation Monitoring Program was presented to manage these aging effects by inspections.

2. Peach Bottom LRA and SER (NUREG-1769-Reference 17)

Peach Bottom identified plant insulation as commodity groups of insulating materials and jacketing. For plant areas where temperature control is considered critical for operation or where high temperature could impact environmental qualification, the insulation is included in the scope of license renewal. For insulation that was in an indoor environment, there were no aging effects requiring management. For insulation that was in an outdoor environment, the aluminum jacketing with stainless steel straps required aging management. The Outdoor, Buried, and Submerged Component Inspection Activities were credited with inspection of this wetted insulation.

3. V. C. Summer Nuclear Station LRA and SER (NUREG 1787- Reference 16)

V.C. Summer stated the insulating properties of thermal insulation were not a license renewal intended function. However some of their thermal insulation was included in the scope of license renewal review due to the potential for falling insulation to impact safety related components. The insulation was identified as being in a high moisture environment. The NRC requested an evaluation of galvanic corrosion between the insulation foil and the pipe external surface in this wetted environment. The site responded that the Inspections for Mechanical Components AMP was adequate for managing loss of material including any galvanic corrosion on the external surfaces.

4. Dresden and Quad Cities LRA and SER (NUREG 1796- Reference 18)

The Dresden and Quad Cities LRA identified that thermal insulation has a variety of purposes. For insulation of plant areas where systems and equipment are in the scope and require temperature control, they were included in the license renewal scope and aging effects were evaluated. A detailed system list is provided to identify the systems that had insulation in the LR scope in the SER. For stainless steel insulation, closed cell foam, quilted fiberglass insulation, calcium silicate and insulation jacketing the application identified there were no aging effects requiring management. For asbestos and other fiberglass in a wetted environment, insulation degradation/loss of insulating characteristics was identified as an aging effect requiring management. The Structures Monitoring Program was identified as the program to manage the aging effects on the insulation.

5. Farley, Units 1 and 2 LRA and SER (NUREG-1825-Reference 19)

The Farley LRA included thermal insulation for the CO_2 tank in LR scope as the only insulation that required review. The insulation was identified as having an "environmental control" function and "change in material properties and cracking" were identified as aging effects managed by the Fire Protection Program. The response to RAI 2.4-8 concerning the intended function of thermal insulation that was accepted in the SER is quoted below:

> "Thermal insulation is not relied upon in FNP's current licensing basis (CLB) to perform any safety related function. Specifically, the thermal insulation at FNP does not serve a safety-related function to limit the temperature of structural steel and/or concrete elements, including the supports for the NSSS components. Thermal insulation is neither installed on the containment liner nor installed in any of the hot pipe penetrations. During normal operations, area and room temperature monitoring activities assure environmental temperatures are maintained within established limits. Environmental control systems that maintain temperatures during power operations and are not relied upon for safe shutdown or accident mitigation (e.g., reactor cavity cooling, containment air recirculation system, etc.) are non safety-related in FNP's CLB."

6. Nine Mile Point Units 1 and 2 LRA and SER (NUREG-1900-Reference 28)

In response to RAI 2.1-7, the applicant stated that an evaluation of thermal insulation used at Nine Mile Point Units 1 and 2 was performed to determine whether plant insulation was credited for performing any license renewal functions. Based upon this review, the applicant concluded that the only intended function to meet license renewal scoping criteria was fire wrap, which meets 10 CFR 54.4(a)(3) and is included within the scope of license renewal. Specifically, these structural steel fire protection coatings are within the scope of license renewal and subject to an AMR.

7. Browns Ferry Units 1, 2 and 3 LRA and SER (NUREG-1843-Reference 22)

   On March 22, 2005, the staff held a teleconference with the applicant to discuss the treatment of insulation. In its response, dated May 18, 2005, the applicant stated that all the mechanical piping and equipment insulation contained in the SR structures as well as some NSR structures have been added to the scope of license renewal, since they meet the criteria of 10 CFR 54.4(a)(2) and (a)(3). Piping and equipment insulation has the intended functions of insulate and integrity. The applicant stated that these intended functions will be added to LRA Table 2.0.1.
   The applicant also stated that piping and equipment insulation and insulation jacketing are component types that are subject to an AMR. LRA Table 2.1.7.2 will be added to reflect these two component types and their intended functions.

4. DISCUSSION OF DIABLO CANYON POSITION

Thermal insulation will be evaluated as a passive, long-lived component during the scoping and screening process. Insulation that has an intended function will be considered in the scope of license renewal and subject to aging management review. Intended functions of insulation typically include minimizing heat load into rooms, thermal protection of nearby components, and/or thermal protection for isolated piping segments in containment. The insulation with an intended function will be included as a component type in each in-scope system and evaluated as a passive, long-lived component during the screening process. The areas where the insulation is considered to have an intended function are identified in Table 1. Aging effects are evaluated consistent with section 4.2 of this position paper.

4.1 Review of Intended Functions of DCPP Insulation

There are significant quantities of insulation installed at DCPP, but the majority of this insulation does not meet the scoping criteria of 10 CFR Part 54.4(a). A large portion of the insulation is installed for thermal efficiency or personnel protection and is not required to satisfy the criteria of 10CFR54.4(a)(1), 10CFR54.4(a)(2), or 10CFR54.4(a)(3).

Insulation may have the specific intended functions of (1) controlling heat load in areas with safety-related equipment, or (2) maintaining integrity such that falling insulation does not damage safety-related equipment.

<u>Criterion 10 CFR 54.4(a)(1)</u>
Safety-related insulation or insulation relied upon to remain functional during and following design basis events are in the scope of license renewal for criteria 10 CFR 54.4(a)(1). According to the DCPP Q-List (Reference 40), safety-related insulation at DCPP is limited to the pressurizer loop seal insulation. The pressurizer loop seal insulation is classified as design Class I. The pressurizer loop seals are insulated to maintain the loop seal water near saturation conditions so that, upon safety valve operation, most of the seal water flashes, thus reducing the hydraulic loading on the downstream piping (Reference 52, section 5.5.12.2). Thus, DCPP insulation will be in the scope of license renewal for criteria 10 CFR 54.4 (a)(1).

Insulation associated with the Safety Injection System, Containment Spray System, Auxiliary Feedwater System, Chemical and Volume Control System, or the Residual Heat Removal System is not required to minimize heat load into rooms during design basis events. In addition, DCPP does not use insulation in the Emergency Diesel Generator exhaust penetrations to maintain temperature of the structure.

Criterion 10 CFR 54.4(a)(2)
Nonsafety-related insulation which fails and prevents satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1) is identified as in the scope of license renewal for criterion 10 CFR 54.4(a)(2). The physical impact hazard needs to be considered for insulation of piping and equipment that are of seismic design or fall within the II/I classification. DCPP DCM T-26, Section 4.1.10 (Reference 43), and SSER 11 (Reference 44) state that the insulation supports were designed to withstand a seismic event for piping and equipment that are of seismic design or fall within the II/I classification. Furthermore, insulation such as fiberglass fiber and similar materials do not have enough mass to constitute a seismic II over I concern when compared to the mass and inherent ruggedness of the safety related components. Metallic fastening materials such as tie wires or banding that are used for supporting/securing calcium silicate or reflective insulation will be in the scope of license renewal for criterion 10 CFR 54.4 (a)(2).

Criterion 10 CFR 54.4(a)(3)
Insulation relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), ATWS (10CFR 50.62) or Station Blackout (10 CFR 50.63) is identified as in the scope of license renewal for criteria 10 CFR 54.4(a)(3).

Insulation may be credited with maintaining a localized area at a low temperature during normal plant operation for limiting the long term aging effects on materials such as concrete or elastomers. DCPP insulation on components is credited for maintaining the qualified life of nearby environmentally qualified components (Reference 41), which meets the EQ criteria of 10CFR54.4(a)(3). A thermal barrier is required between the rupture restraint and the stainless steel tubing for LT-503 to maintain the qualified life of nearby environmentally qualified components. Thus, DCPP insulation will be in-scope under 10 CFR 54.4 (a)(3).

4.2 Aging Effects for Insulation

At DCPP, allowable insulating materials and quality requirements for safety class components are given in procedure MIP C-4.0 and specifications 8737 and 8748 (References 46 and 47). The types of insulation that were utilized include stainless steel reflective, asbestos, fiberglass fiber and similar materials. Appendix A identifies all possible insulation materials utilized at DCPP, environment (air-indoor uncontrolled), aging effects, and associated references. Table 1 identifies DCPP Insulation within the scope of license renewal.

Table 1. Diablo Canyon Power Plant Insulation within the Scope of License Renewal

	Insulation Area	Insulation Material	Basis to be In Scope	54.4(a) Criterion	System(s) Involved
1	Insulation Supports (thermal insulation strapping, not the thermal insulation)	Stainless Steel (material for the strapping around the thermal insulation)	DCM T-26 & SSER 11	(a)(2)	ZSUP
2	Pressurizer Loop Seal	Calcium Silicate	DCPP Q-List	(a)(1)	07
~~3~~	~~Environmentally Qualified Component Insulation in Containment (LT-503)~~	~~TBD~~	~~Calculation HVAC-98-02~~		~~80H~~

Additional Information
1. The Reactor Vessel (RV) insulation is Design Class II per the DCPP Q-List. DCPP UFSAR Table 3.2-1 defines Design Class II as important to reactor operation but not essential to safety. Therefore, the RV insulation is not in the scope of LR.

2. The thermal barrier for LT-503 (Steam Generator Wide Range Transmitter) is not in-scope of LR. The thermal barrier protects the stainless steel instrument tubing for LT-503. While LT-503 is safety-related and in-scope of LR, the thermal barrier is not safety-related and thus not in-scope for (a)(1). Failure of the thermal barrier would affect the instrument tubing for LT-503 but not the operation of LT-503 itself. Therefore the thermal barrier is not in-scope for (a)(2). The thermal barrier is also not relied upon for any of the five regulated events. Specifically, although LT-503 is an EQ component, the thermal barrier is not an EQ component, and thus it is not in-scope for (a)(3).

Insulation Supports
Metallic fastening materials such as tie wires or banding that are used for supporting/securing calcium silicate or reflective insulation are made of stainless steel (Reference 45 Appendix 9.1 section 3.7). Per the EPRI Mechanical Tools (Reference 32) and NUREG-1801 (Reference 33), there are no aging effects that require management for stainless steel in an indoor air environment.

Damage Caused by Events
Insulation may be damaged by personnel stepping on the insulation or impacting it during maintenance. This type of damage is considered an event, not an aging effect requiring management. When damage to insulation is identified, it is evaluated and corrected as necessary as a part of the corrective action program. Similarly, insulation may be damaged by spills or leaks. This type of damage is also considered an event and not aging-related. When damage to insulation from spills or leaks is identified it is evaluated and corrected as necessary as a part of the corrective action program.

Aluminum & Stainless Steel Sheathing (Jacketing)
The fiberglass fiber, calcium-silicate, and similar materials have sheathing of the external surface that is typically aluminum or stainless steel. EPRI Mechanical Tools (Reference 32) and NUREG-1801 (Reference 33) do not identify aging effects that require management for

aluminum or stainless steel in an indoor air environment without condensation. DCPP procedure MIP C-4 section 3.6.1a does not allow aluminum jacketing to be used in Containment or in locations where corrosive spillage can occur (Reference 45, Section 3.6.1a).

Leaching of Contaminates (Regulatory Guide 1.36)
DCPP procedure MIP C-4.0 is consistent with Regulatory Guide 1.36 requirements to protect stainless steel components against stress corrosion cracking that could be caused by the leaching of contaminants from insulation (Reference 45 Appendix 9.1 section 3.1.5).

SER for Six Insulation Groups
The SER for Dresden and Quad Cities LRA (Reference 18) also supports the evaluation:

> "In the LRA Table 3.2-2 …. Table 3.3-2…..and Table 3.4-2 … provide the following technical justifications for concluding that there are no aging effects requiring management for six specific insulation groups:
>
> "(1) The plant indoor environment is not conducive to promoting aging degradation of NUKON quilted fiberglass insulation.
>
> "(2) Stainless steel mirror insulation materials are not subject to any viable aging mechanism in the absence of aggressive chemical species.
>
> "(3) Stainless steel insulation jacketing materials are not subject to any viable aging mechanism in the absence of aggressive chemical species.
>
> "(4) Closed-cell foam insulation is susceptible to degradation when exposed to UV light. The plant indoor environment is not conducive to promoting aging degradation of closed-cell foam insulation.
>
> "(5) Aluminum is reactive but develops an oxide film that protects it from further corrosion. No viable aging effects exist in the indoor environment for aluminum insulation jacketing.
>
> "(6) The plant outdoor environment is not conducive to promoting aging degradation of jacketed calcium silicate insulation.
>
> "The staff finds these justifications to be reasonable and acceptable.
>
> "The aging effects identified in the LRA for the isolation commodity group are consistent with industry operating experience for the materials and environments listed. The staff finds that all the plausible aging effects were identified and that the aging effects listed are appropriate for the combination of materials and environments specified."

DCPP Plant-Specific Operating Experience Review
Plant-specific operating experience originating from action requests (ARs) was examined to determine if there were any plant-specific aging effects for thermal insulation. The AR search

string utilized keywords likely to identify aging effects such as spalling, corrosion, crack, aging, degrade, etc. The search was based on ARs covering a period of five years prior to the review (from January 1, 2002 to present). ARs A0554164, A0563058, A0577239, and A0600692 identified damaged insulation due to pipe or tank leakage. This operating experience did not identify any insulation aging effects since the damaged insulation was due to non-aging related events such as pipe leakage. All other operating experience which identified damaged/aged insulation was determined to be out of the scope of TR-10DC since the aging was for electrical insulation (Reference 48, AR A0572020).

Therefore, based on an evaluation of the materials and environment and the site specific operating experience, there are no aging effects identified for the thermal insulation used at DCPP.

4.3 Other Insulation Related Issues

Other license renewal insulation-related issues include:

- the potential for chemical contaminants in the insulation causing cracking of stainless steel external surfaces
- Assessment of Debris Accumulation on PWR Sump Performance (GSI-191)

If there are contaminants such as chlorides, fluorides or sulfates in the insulation that can come in contact with the pipe external surfaces, this could cause cracking at the pipe external surface from stress corrosion cracking/intergranular attack. This is identified as an aging effect for external surfaces in the mechanical tools and must be evaluated to identify if this is an aging effect requiring management for each site. As described in procedure MIP C-4.0, Sections 7.3.8 & 7.3.9, the selection and procurement of all nonmetallic thermal insulation assure that the leachable concentrations of chloride, fluoride, sodium, and silicate are in accordance with Regulatory Guide 1.36. Therefore contaminants are not a concern for the DCPP insulation on stainless steel components since adequate controls are in place to ensure insulation that is installed is free of contaminants.

Clogging the Containment Sump screens is addressed in FSAR Section 6.2.2.3.3.8 and is concluded that the debris will not affect the performance of the sump. Generic Safety Issue 191 will be resolved for DCPP Units 1 and 2 through completion of actions for Generic Letter 2004-02, “Potential Impact of Debris Blockage on Emergency Recirculation During Design Basis Accidents at Pressurized-Water Reactors” All work will be completed by the end of outages beginning in February 2008 (Unit 2) and January 2009 (Unit 1) (References 49 and 50, respectively). Therefore, Containment Sump Clogging is not a concern for the DCPP containment insulation.

5. SUMMARY AND CONCLUSION

The review in section 3.0 identified that some license renewal applications have not addressed mechanical component thermal insulation or have specifically identified thermal insulation is not in the license renewal scope. Other license renewal applicants have identified some insulation in certain locations that may be considered in scope but is in a dry air environment and does not require an aging management program. Some applicants identified some insulation types that when in a specific wetted environment would experience aging effects requiring management.

The review for DCPP insulation in section 4 identified several locations where insulation is within the scope of license renewal and requires aging management.

Section 4.1 identifies thermal insulation on mechanical components at DCPP in the scope of license renewal that support an intended function to:

- maintain pressurizer loop seal temperature,
- provide support to insulation such that falling insulation does not damage safety-related equipment, and
- reduce heat load to maintain environmental qualification of nearby components.

Section 4.2 evaluated aging effects for the insulation used at DCPP. The review concluded this insulation does not have any aging effects requiring aging management.

Section 4.3 identified other related insulation issues such as leaching of aggressive contaminates and clogging of the containment sump screens (GSI-191).

1. Contaminants are not a concern for the DCPP insulation installed on stainless steel components since controls are in place to ensure insulation that is installed is free of contaminants.
2. Containment Sump Clogging is not a concern for the DCPP containment insulation since actions required by Generic Letter 2004-02 will be completed by the end of outages beginning in February 2008 and January 2009.

In conclusion, the DCPP LRA will identify thermal insulation that is in the scope of license renewal. However, none of the insulation has any aging effects requiring aging management.

6. REFERENCES

1. Title 10 of the Code of Federal Regulations, Part 54, "Requirements for the Renewal of Operating Licenses for Nuclear Power Plants."

2. Generic Letter 2004-02: Potential Impact of Debris Blockage On Emergency Recirculation During Design Basis Accidents at Pressurized Water Reactors, September 13, 2004

3. Project Instruction PI-1, "Scoping and Screening of Systems, Structures, and Components, Rev. 4, Dated October 12, 2007.

4. NUREG-1800, Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants, U.S. Nuclear Regulatory Commission, Rev. 1, September 2005.

5. NEI-95-10, Industry Guideline for Implementing the Requirements of 10 CFR Part 54 – the License Renewal Rule, Rev. 6, Nuclear Energy Institute, June 2005.

6. NUREG-1705, Safety Evaluation Report Related to the License Renewal of Calvert Cliffs Nuclear Power Plant, U.S Nuclear Regulatory Commission

7. NUREG-1723, Safety Evaluation Report Related to the License Renewal of Oconee Nuclear Power Station, U.S. Nuclear Regulatory Commission.

8. NUREG-1743, Safety Evaluation Report Related to the License Renewal of Arkansas Nuclear One, Unit 1, U.S. Nuclear Regulatory Commission

9. NUREG-1759, Safety Evaluation Report Related to the License Renewal of Turkey Point Nuclear Plant Units 1 and 2, U.S. Nuclear Regulatory Commission.

10. NUREG-1766, Safety Evaluation Report Related to the License Renewal of North Anna Power Station, Units 1 and 2 and Surry Power Station Units 1 and 2, U.S. Nuclear Regulatory Commission.

11. NUREG-1779, Safety Evaluation Report Related to the License Renewal of St Lucie Nuclear Plant, Units 1 and 2, U.S. Nuclear Regulatory Commission.

12. NUREG-1782, Safety Evaluation Report Related to the License Renewal of Fort Calhoun Station, Unit 1, U.S. Nuclear Regulatory Commission.

13. NUREG-1772, Safety Evaluation Report Related to the License Renewal of McGuire Units 1 and 2 and Catawba Station, Units 1 and 2, U.S. Nuclear Regulatory Commission.

14. NUREG-1785, Safety Evaluation Report Related to the License Renewal of H.B. Robinson Steam Electric Plant, Unit 2, U.S. Nuclear Regulatory Commission.

15. NUREG-1786, Safety Evaluation Report Related to the License Renewal of R.E. Ginna Nuclear Power Plant, U.S. Nuclear Regulatory Commission.

16. NUREG-1769, Safety Evaluation Report Related to the License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3, U.S. Nuclear Regulatory Commission.

17. NUREG-1796, Safety Evaluation Report Related to the License Renewal of Dresden and Quad Cities Nuclear Power Station, U.S. Nuclear Regulatory Commission.

18. NUREG-1787, Safety Evaluation Report Related to the License Renewal of Virgil. C. Summer Nuclear Station, U.S. Nuclear Regulatory Commission.

19. NUREG-1825, Safety Evaluation Report Related to the License Renewal of Joseph M. Farley Nuclear Plant Units 1 and 2, U.S. Nuclear Regulatory Commission.

20. NUREG-1828, Safety Evaluation Report Related to the License Renewal of ANO-2, U.S. Nuclear Regulatory Commission.

21. NUREG-1831, Safety Evaluation Report Related to the License Renewal of D.C. Cook Units 1 and 2, U.S. Nuclear Regulatory Commission.

22. NUREG-1843, Safety Evaluation Report Related to the License Renewal of Browns Ferry Nuclear Plant Units 1, 2, and 3. U.S. Nuclear Regulatory Commission, April 2006.

23. NUREG-1838, Safety Evaluation Report Related to the License Renewal of Millstone Nuclear Power Station Units 2 and 3, U.S. Nuclear Regulatory Commission.

24. NUREG-1839, Safety Evaluation Report Related to the License Renewal of Point Beach Nuclear Plant. U.S. Nuclear Regulatory Commission.

25. NUREG-1856, Safety Evaluation Report Related to the License Renewal of Brunswick Steam Electric Plant. U.S. Nuclear Regulatory Commission.

26. NUREG-1865, Safety Evaluation Report Related to the License Renewal of Monticello Nuclear Generating Plant. U.S. Nuclear Regulatory Commission.

27. NUREG-1803, Safety Evaluation Report Related to the License Renewal of Edwin I Hatch Nuclear Plant Units 1 and 2, U.S. Nuclear Regulatory Commission.

28. NUREG-1900, Safety Evaluation Report Related to the License Renewal of Nine Mile Point Nuclear Plant Units 1 and 2. U.S. Nuclear Regulatory Commission, June 2006.

29. NUREG-1871, Safety Evaluation Report Related to the License Renewal of Palisades Nuclear Generating Plant. U.S. Nuclear Regulatory Commission, September 2006.

30. Safety Evaluation Report Related to the License Renewal of Oyster Creek Nuclear Generating Plant. U.S. Nuclear Regulatory Commission, March 2007.

31. SCE&G Technical Report RC-02-0159, Criteria 2 Supplement to the Application for Operating License, September 12, 2002. Adams No ML022630347.

32. EPRI 1010639, Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Revision 4, January 2006, Electric Power Research Institute.

33. NUREG-1801, Generic Aging Lessons Learned (GALL) Report, Rev 1, September 2005.

34. Application for Renewed Operating License – Wolf Creek Generating Station.

35. Palo Verde Nuclear Generating Station Thermal Insulation License Renewal Position Paper (TR-10PV), Rev. 0

36. Safety Evaluation Report Related to the License Renewal of Pilgrim Nuclear Power Station. U.S. Nuclear Regulatory Commission, June 2007.

37. Draft Safety Evaluation Report Related to the License Renewal of Vermont Yankee Nuclear Power Station. U.S. Nuclear Regulatory Commission, March 2007.

38. Draft Safety Evaluation Report Related to the License Renewal of James A. Fitzpatrick Nuclear Power Plant. U.S. Nuclear Regulatory Commission, July 2007.

39. NUREG/CR-6874, GSI-191: Experimental Studies of Loss-of-Coolant-Accident-Generated Debris Accumulation and Head Loss with Emphasis on the Effects of Calcium Silicate Insulation, May 2005.

40. DCPP Q-List, dated September 2008.

41. DCPP Calculation HVAC-98-02, “Determine Temperature of EQ Components Due to the Removal of Min-K Insulation,” Rev. 1

42. DCPP Technical Specification 3.6, “Containment Systems”

43. DCM T-26, “Pipe Support Analysis,” Rev. 3A

44. SSER 11, “Evaluation of Pacific Gas and Electric Company’s Systems Interaction Program for Seismically-Induced Events for the Diablo Canyon Nuclear Plant, Units 1 and 2”

45. DCPP Procedure MIP C-4.0, “Thermal Insulation,” Rev. 4

46. Specification 8737, "Finishing and Installing Conventional Thermal Insulation, Units 1 and 2."

47. Specification 8748, "Finishing and Installing of Removable Insulation for Units 1 and 2."

48. DCPP Insulation Operating Experience Whitepaper, dated January 2008.

49. NRC Incoming Letter, “Diablo Canyon Power Plant, Unit No. 1 - Generic Letter 2004-02 “Potential Impact Of Debris Blockage On Emergency Recirculation During Design Basis Accidents At Pressurized Water Reactors” Extension Request Approval. U.S. Nuclear Regulatory Commission, April 2007.

50. NRC Incoming Letter, “Diablo Canyon Power Plant, Unit No. 2 - Generic Letter 2004-02 “Potential Impact Of Debris Blockage On Emergency Recirculation During Design Basis Accidents At Pressurized Water Reactors” Extension Request Approval. U.S. Nuclear Regulatory Commission, January 2007.

51. DCPP Procedure OP A4A:IV, “Partial Draining of Pressurizer Safety Valve Loop Seals,” Rev. 6.

52. DCPP FSAR Updated Revision 1<u>8</u>~~7~~.

Appendix A

Insulation	Description	Environment	Aging Effect	Reference	Notes
Asbestos-Free Calcium-Silicate with Jacketing	Fiberglass	Air-indoor uncontrolled	None.	EPRI Mechanical Tools Appendix E, Section 3.6.1 LRAs for Fitzpatrick, Pilgrim, Vermont Yankee & Oyster Creek all show no aging effect	TR-8WC &TR-10PV (Attachment D) also shows no aging effect
Mineral Wool	Inorganic Fibers	Air-indoor uncontrolled	None.	EPRI Mechanical Tools Appendix E, Section 3.6.4	Not used in containment (MIP C-4.0, Section 3.4.1)
Glas-Fab	Woven Glass Fabric	Air-indoor uncontrolled	None.	EPRI Mechanical Tools Appendix E, Section 3.6.1 LRAs for Fitzpatrick, Pilgrim, Vermont Yankee & Oyster Creek all show no aging effect	TR-8WC &TR-10PV (Attachment D) also shows no aging effect
Asbestos Cloth and Woven Fiber	Inorganic Fibers	Air-indoor uncontrolled	None.	EPRI Mechanical Tools Appendix E, Section 3.6.4; Oyster Creek LRA Table 3.5.2.1.19	
Stainless Steel	Metal	Air-indoor uncontrolled	Susceptible to pitting & crevice corrosion in condensation	EPRI Mechanical Tools Appendix E, Section 3.1.3, 3.1.4	Indoor plant air at DCPP does not have significant condensation, therefore, this aging effect is not applicable.
			Radiation Embrittlement if fluence is $>10^{17}$ neutrons/cm^2	EPRI Mechanical Tools Appendix D, Section 3.3.2	According to several LRAs (Palisades, Oyster Creek, Robinson, Point Beach), stainless steel in a containment air atmosphere requires no aging management.

Insulation	Description	Environment	Aging Effect	Reference	Notes
Stainless Steel Jacketing	Metal	Air-indoor uncontrolled	Susceptible to pitting & crevice corrosion in condensation	EPRI Mechanical Tools Appendix E, Section 3.1.3, 3.1.4	Indoor plant air at DCPP does not have significant condensation, therefore, this aging effect is not applicable.
			SCC is a concern if T > 140F and exposure to salt air	EPRI Mechanical Tools Appendix E, Section 3.2.2, and Appendix E, Table 4-1	SS may not be used in locations where SCC can occur. (MIP C-4.0 Section 3.1.5) Therefore, this aging effect is not applicable.
			MIC is of concern if in condensation	EPRI Mechanical Tools Appendix E, Section 3.1.6	Indoor plant air at DCPP does not have significant condensation, therefore, this aging effect is not applicable.
			Radiation Embrittlement if fluence is $>10^{17}$ neutrons/cm^2	EPRI Mechanical Tools Appendix D, Section 3.3.2	According to several LRAs (Palisades, Oyster Creek, Robinson, Point Beach), stainless steel in a containment air atmosphere does not require any aging management.
Aluminum Jacketing	Metal	Air-indoor uncontrolled	Galvanic, crevice, & pitting corrosion in condensation	EPRI Mechanical Tools Appendix E, Section 3.1.2 - 4	Indoor plant air at DCPP does not have significant condensation, therefore, this aging effect is not applicable.
			Blistering in aggressive corrosive environments	EPRI Mechanical Tools Appendix E, Section 3.2.1	Aluminum jacketing may not be used in locations where corrosive spillage can occur. (MIP C-4.0 Section 3.6.1a) Therefore, this aging effect is not applicable. Aluminum jacketing is not used in containment (MIP C-4.0, Section 3.1.3)
PVC Jacketings	Elastomer	Air-indoor uncontrolled	None.	Engineered Material Handbook, Vol. 2	PVC Jacketings are not used in radiological environments (MIP C-4.0, Section 3.6.1c)

Insulation	Description	Environment	Aging Effect	Reference	Notes
Cerafelt	Refractory Fiber Felt	Air-indoor uncontrolled	None.	EPRI Mechanical Tools Appendix E, Section 3.6.4 LRAs for Fitzpatrick, Pilgrim, Vermont Yankee & Oyster Creek all show no aging effect	TR-8WC &TR-10PV (Attachment D) also shows no aging effect
Blanket Kaowool	Ceramic Fiber Blanket	Air-indoor uncontrolled	None.	EPRI Mechanical Tools Appendix E, Section 3.6.4 LRAs for Fitzpatrick, Pilgrim, Vermont Yankee & Oyster Creek all show no aging effect	TR-8WC &TR-10PV (Attachment D) also shows no aging effect
Spinglas	Glass Fibers and Thermosets	Air-indoor uncontrolled	None.	EPRI Mechanical Tools Appendix E, Section 3.6.1 LRAs for Fitzpatrick, Pilgrim, Vermont Yankee & Oyster Creek all show no aging effect	TR-8WC &TR-10PV (Attachment D) also shows no aging effect
NUKON	Fiberglass	Air-indoor uncontrolled	None.	EPRI Mechanical Tools Appendix E, Section 3.6.1 LRAs for Fitzpatrick, Pilgrim, Vermont Yankee & Oyster Creek all show no aging effect	TR-8WC &TR-10PV (Attachment D) also shows no aging effect
CLAREMAT	Glass Fiber Blanket	Air-indoor uncontrolled	None. None.	EPRI Mechanical Tools Appendix E, Section 3.6.1 LRAs for Fitzpatrick, Pilgrim, Vermont Yankee & Oyster Creek all show no aging effect	TR-8WC &TR-10PV (Attachment D) also shows no aging effect
MIN-K	Microporous Silica	Air-indoor uncontrolled	None.	EPRI Mechanical Tools Appendix E, Section 3.6.1 LRAs for Fitzpatrick, Pilgrim, Vermont Yankee & Oyster Creek all show no aging effect	TR-8WC &TR-10PV (Attachment D) also shows no aging effect

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Insulation	Description	Environment	Aging Effect	Reference	Notes
Temp-Mat	Fiberous Glass Blanket	Air-indoor uncontrolled	None.	EPRI Mechanical Tools Appendix E, Section 3.6.1 LRAs for Fitzpatrick, Pilgrim, Vermont Yankee & Oyster Creek all show no aging effect	TR-8WC &TR-10PV (Attachment D) also shows no aging effect
Micro-lok	Fiberglass	Air-indoor uncontrolled	None.	EPRI Mechanical Tools Appendix E, Section 3.6.1 LRAs for Fitzpatrick, Pilgrim, Vermont Yankee & Oyster Creek all show no aging effect	TR-8WC &TR-10PV (Attachment D) also shows no aging effect
Foamglas	Cellular Glass	Air-indoor uncontrolled	None.	EPRI Mechanical Tools Appendix E, Section 3.6.1 LRAs for Fitzpatrick, Pilgrim, Vermont Yankee & Oyster Creek all show no aging effect	TR-8WC &TR-10PV (Attachment D) also shows no aging effect
Pittwrap	Cellular Glass	Air-indoor uncontrolled	None.	EPRI Mechanical Tools Appendix E, Section 3.6.1 LRAs for Fitzpatrick, Pilgrim, Vermont Yankee & Oyster Creek all show no aging effect	TR-8WC &TR-10PV (Attachment D) also shows no aging effect
Armstrong Armaflex	Closed-Cell Elastomeric Foam	Air-indoor uncontrolled	Needs a plant-specific evaluation.	EPRI Mechanical Tools Appendix D, Section 3.5	Per the operating experience search, no instances of Armstrong Armaflex aging have been found at DCPP
			Hardening and loss of strength when exposures exceed 10^6 rads total dose over the period of 60 years	EPRI Structural Aging Effects, Section 7.3.1	Not used in containment (MIP C-4.0, Section 3.4.1)

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LICENSE RENEWAL FEASIBILITY STUDY

WORK GUIDELINE 1

INTEGRATED PLANT ASSESSMENT

Manager Approval/ Terence L Grebel Date/ 10/20/09

Revision 7
October 2009

FOREWORD

This work guideline implements 10 CFR 54, required for the Integrated Plant Assessment (IPA) by confirming the Diablo Canyon Power Plant (DCPP) License Renewal Feasibility Study review processes and responsibilities adequately demonstrate that management of aging is such that there is an acceptable level of safety during the period of extended operation. This work guideline is intended to provide specific detail and working-level guidance for creating required IPA reports up to and including owner's acceptance. As appropriate, guidelines for interfacing with contractors related to the preparation of the IPA portion of license renewal are addressed.

This work guideline is designated to ensure the following:

- Documents prepared to support the IPA portion of license renewal are accurate, complete, consistent, and address all pertinent regulatory requirements.

- IPA reports receive thorough technical and management reviews.

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ATTACHMENTS

1. APPLICABLE REGULATIONS AND GUIDANCE

The primary regulation applicable to License Renewal IPA Reports is 10 CFR 54, “Requirement for Renewal of Operating Licenses for Nuclear Power Plants.” Compliance with this regulation is mandatory; exemptions require formal approval by the NRC. An exception request must cite compelling reasons why an exemption is justified. The NRC may reject the request unless compliance would result in undue hardship or costs, or the proposed exemption would result in a clear benefit to the public health and safety. Therefore, every effort should be made by PG&E to ensure not only that compliance with regulations is achieved, but also that such compliance is clearly and completely documented.

NUREG – 1800, "Standard Review Plan for License Renewal Applications for Nuclear Power Plants," and NUREG – 1801, "Generic Aging Lessons Learned (GALL)" provide specific guidance on acceptable methods to implement and demonstrate compliance with regulations. While these documents are not regulatory requirements, the guidance details provided in these documents effectively become regulatory requirements once a licensee commits to conformance with the NUREG. Further, much of the information contained in the SRPs should be viewed as equivalent to requirements as the NRC staff uses such information in identifying compliance with or deviation from regulations.

DCPP Procedure XI1.ID1, "Regulatory Correspondence Processing" is used to satisfy XI1, "Regulatory Interface," requirements by establishing controls for processing incoming and outgoing regulatory correspondence related to the facilities. This work guideline provides additional information and guidance for PG&E reviewers to satisfy the requirements of XI1.ID1.

2. RESPONSIBILITIES

Prior to issuance to PG&E for review, license renewal documents are prepared and reviewed at the STARS Center of Business (COB). The COB uses administrative procedure PI-1 for the scoping and screening reports, PI-2 for the Aging Management Review (AMR), and PI-3 for the Time Limited Aging Analyses (TLAA).

Responsibilities for PG&E personnel for Diablo Canyon are as follows:

Primary Reviewers of IPA reports (Reviewers whose comments are required)

- The lead LRFS engineer shall act as the lead licensing engineer, and is responsible for coordinating the LRFS draft application and associated IPA reports. Interface with lead authors to ensure conformance with license renewal processes. Ensure compliance with applicable regulatory requirements or provide adequate justification for noncompliance. Coordinate resolution of comments. See Appendix 7.3 of XI1.ID1 for lead LRFS engineer expectations. The lead technical reviewer may also be the lead LRFS engineer.

- The lead technical reviewer is responsible for reviewing all technical content in the License Renewal Feasibility documents.

- The cross-discipline reviewer, if necessary, is responsible for providing review and concurrence of those portions of a License Renewal Feasibility documents that impact the reviewer's department.

- The independent technical reviewer (ITR) is responsible for independently verifying technical information contained in the License Renewal Feasibility documents.

- The Project Manager is responsible for providing overall management concurrence of a submittal.

Secondary Reviewer (Reviewers whose comments are optional)

- A secondary reviewer is responsible for providing review for informational purposes only.

Project Manager

- Provide overall management of IPA planning and scheduling and ensure timely author and reviewer assignments for reports.

- Perform owners acceptance for all LRFS IPA reports.

3. INTEGRATED PLANT ASSESSMENT

3.1 Scoping and Screening

Scoping and Screening production work is done at the STARS Center of Business (COB). Systems and Structures are scoped in according to the methodology described in chapter two of the NUREG – 1800, "Standard Review Plan (SRP)." Components of the in-scope systems and structures that meet the criteria specified in NUREG – 1800 are screened out, as no aging management is required. Also, Safety Related boundaries are identified through DCPP system drawings. Scoping and Screening results become Chapter 2 of the Draft License Renewal Application (LRA) and are compiled into four parts:

- Plant Level Scoping Results
- System Scoping and Screening Results: Mechanical Systems
- Scoping and Screening Results: Structures

- Scoping and Screening Results: Electrical and Instrumentation and Controls Systems

3.2 Aging Management Review

Aging Management Review (AMR) recommendations are described in chapter three of the SRP and results of the review become Chapter 3 and Appendix B of the draft LRA. The AMR consists of an Aging Evaluation and assigns Aging Management Programs.

3.2.1 Aging Evaluation

The Aging Evaluation addresses material and environment combinations and the associated aging effect. For every aging effect identified, an Aging Management Program is assigned to manage the aging through the period of extended operation. As part of the Aging Evaluation, system level Operating Experience is conducted to review the plant history and ensure all aging effects have been identified.

3.2.2 Aging Management Programs

NUREG – 1801 describes the recommended programmatic approach to managing the aging through the period of extended operation (PEO). Existing DCPP procedures and programs will be used to fulfill these recommendations. There may be a need to enhance a current procedure to meet the NUREG – 1801 recommendations or provide a technical justification for taking and exception to NUREG – 1801 recommendations. There may also be a need to create a new program to meet the recommendations of NUREG – 1801.

3.3 Time-Limited Aging Analyses

Time-Limited Aging Analyses (TLAAs) are described in chapter four of the SRP. A TLAA Report is developed to describe the (1) DCPP process used to identify potential TLAAs; (2) current and historical DCPP design bases for Class 1 components; and (3) disposition potential TLAAs. Results of this TLAA review become Chapter 4 of the draft LRA and are compiled into eight standard sections:

- Introduction
- Neutron Embrittlement
- Metal Fatigue
- Environmental Qualification
- Pre-stressed Containment Tendons
- Containment
- Plant-Specific Analyses
- Exemptions

3.4 Environmental Report

The Environmental Report review process and development is described in the License Renewal Feasibility Study Work Guideline 2, Environmental Report.

4. PRODUCT REVIEWS

Phase I Review

Phase I review consists of an initial or comparison review cycle by the LRFS engineer and project manager using Attachment 1, DCPP Reviewer Checklist, or Attachment 3, DCPP TLAA Reviewer Checklist, as a detailed review guidance document. The purpose of the Phase I review is to ensure a high-quality, technically accurate document that meets the regulatory requirements and is ready for a broader review during Phase II.

A comparison review is to be completed for documents received by the project engineer which contain changes from a previous plant reviewed revision. The review shall identify all changes. All technical changes, verified by the project manager and/or assistant project manager, shall undergo a Phase II review to ensure that all technical content of the final document has been reviewed by an ITR and Subject Matter Expert (SME) in accordance with XI1.ID1. Editorial changes are not required to undergo a Phase II review and can be resolved by the lead LRFS engineer.

The lead technical reviewer and project manager should concur with the draft before release for Phase II review.

Phase II Review

Review and Comment Process

Primary reviewers shall review the documents and provide comments (or indicate they have no comment) to the lead LRFS engineer by the requested due date. The lead LRFS engineer shall actively pursue obtaining comments from primary reviewers.

The scoping, screening, aging evaluation reports, aging management programs, and TLAA Report sections will go through a Diablo Canyon Engineer review. The engineer review guidance is provided in Attachment 2.

Changes to a previously reviewed Aging Management Program are indicated with "track changes" during the Phase II review, and it is only these track changes that are required to be reviewed by the primary reviewers who have previously reviewed the document.

The LRFS engineer shall use Attachment 1, DCPP Reviewer Checklist, or Attachment 3, DCPP TLAA Reviewer Checklist, as a guidance document during the review:

Scoping Report

Items 1 through 7

Boundary Drawings

Item 8 – Identify oddities such as: tank instrumentation penetrations, flame arresters, green/red highlighted interfaces, the termination of red highlighted lines, etc.

Screening Report

Items 9 through 14

Item 10 – Identify unexpected material/environment combinations present, and expected material/environment combinations not present

Aging Evaluation Report

Items 15 – 17

Aging Management Program

Items 18 through 25

TLAA Report section

Items 1 through 5

The ITR shall, using best engineering judgment via a sample population, verify the following items of the DCPP Reviewer Checklist. Review items on the DCPP Checklist are implemented at the ITR's discretion.

Secondary reviewers should review the documents for information only and may provide comments to the lead LRFS engineer. If comments are provided, they must be forwarded to the lead LRFS engineer by the requested due date.

Comment Incorporation Process

The lead LRFS engineer shall facilitate the resolution of technical comments and provide feedback on the resolution of the comments to the reviewer.

When the scoping, screening, aging evaluation reports, aging management programs, and TLAA Report sections are issued to the LRFS engineer, any comments shall be returned to the preparer by the agreed scheduled date. Once returned, the preparer shall incorporate reviewer comments and submit the scoping, screening, aging evaluation reports, aging management programs, and TLAA Report sections back to the reviewer by the agreed scheduled date for comment resolution. The lead LRFS engineer is responsible to ensure all comments are adequately resolved in accordance with XI1.ID1.When all comments are resolved, the document can be "owner accepted" by the LRFS Project Manager (PM) or Assistant Project Manager.

Comment Incorporation of Subject Matter Expert (SME) Review

The comments, related to scoping, screening, aging evaluation reports, or TLAA Report sections, provided to the LRFS project will be passed on to the COB to resolve as part of the project's review of the Scoping and Screening Technical Report and integrated TLAA Report. The comments provided to the LRFS project will be passed on to the COB to resolve as all of the required DCPP reviews are completed.

5. REVIEW TRACKING

Reviewer comments will be tracked, recorded, and resolved at each review phase. The XI1.ID1 Record of Review Checklist should be used to track the completed reviews. A current version of the XI1.ID1, Record of Review Checklist, should be obtained at the following FileNET location: NPG Library:/NPG Manual/00, Forms. Primary and secondary reviewers are identified and the resolution of all comments is all captured on the tracking sheet. The reviewers comments shall be documented and saved in FileNET along with the documents that were reviewed indicating any track changes. The comment tracking forms shall be saved in FileNET once the document has been owner's accepted.

XI1.ID1 Record of Review Checklists should be completed each time a document is revised so that XI1.ID1 Phase 2 Review credit may be taken if necessary. For example, if an entire section is reviewed at Revision 1 by the ITR, credit may be taken for the ITR Revision 1 review in the Revision 2 document for those sections that were not revised. Thus, the ITR only needs to review the revised sections.

6. NRC REQUESTS FOR ADDITIONAL INFORMATION

After submittal of the License Renewal Application, the NRC may require additional information to complete their review. If a Request for Additional Information (RAI) is received, the response should be tracked to completion in accordance with XI1.ID1, Section 5.3 and XI4.ID1, Section 5.4. A Notification should be initiated and assigned to Licensing with Tasks initiated for the appropriate subject matter expert.

Report Title:	Date Issued:	Date Comments Due:	Reviewer(s):

Item No.	Review Item	Comment	References Reviewed	Item Complete
Scoping Report Review ☐ N/A				
1.	Review system description section	☐Y ☐N	☐ N/A	☐
	a) Purpose and system boundary are identified ☐ Complete ☐ N/A b) Level of detail: no component level info or system interface discussions, compare with Wolf Creek SER ☐ Complete ☐ N/A c) Primary FSAR references listed ☐ Complete ☐ N/A			
2.	Review system function	☐Y ☐N	☐ N/A	☐
	a) Function summary present for all "yes" questions ☐ Complete ☐ N/A b) Description of spatial effects, if any ☐ Complete ☐ N/A			
3.	Review scoping questions	☐Y ☐N	☐ N/A	☐
	a) Answers are consistent with CLB or DCMs and/or have references ☐ Complete ☐ N/A b) Answers are consistent with the five regulated events position papers ☐ Complete ☐ N/A c) Each ‘yes’ has a system intended function ☐ Complete ☐ N/A			
4.	Review the identification of system functions	☐Y ☐N	☐ N/A	☐
	a) Verify the “yes” scoping questions are all included ☐ Complete ☐ N/A b) ‘No’ answer states: The system/structure is not credited in any plant CLB or in any plant-specific compliance to FP, EQ, ATWS, PTS, and SBO. ☐ Complete ☐ N/A c) Verify the references (CLB, DCM, or regulated events) are directly tied to the scoping package; includes boundary drawings ☐ Complete ☐ N/A			
5.	Review the identification of supporting systems	☐Y ☐N	☐ N/A	☐
	a) Verify all supporting systems are listed ☐ Complete ☐ N/A b) Verify support systems have a solid CLB reference ☐ Complete ☐ N/A			
6.	Check for open items and verify progress towards closure (N/A if no open items) ☐ Complete ☐ N/A	☐Y ☐N	☐ N/A	☐

Item No.	Review Item	Comment	References Reviewed	Item Complete
7.	Verify CLB/DCM references are most current revisions ☐ Complete ☐ N/A	☐Y ☐N	☐ N/A	☐
Review Boundary Drawings ☐ N/A				
8.	Review boundary drawings	☐Y ☐N	☐ N/A	☐
	a) (a)(1) & (a)(3) are highlighted green; (a)(2) is highlighted red ☐ Complete ☐ N/A b) (a)(2) consistent with anchor locations ☐ Complete ☐ N/A c) Instrument lines highlighted only to the pressure boundary ☐ Complete ☐ N/A d) Check for highlighted/colored valves, vents, and drains ☐ Complete ☐ N/A e) Verify number format (LR-DCPP-XX-1067YY, where XX is the LRID and YY is Sys No.) ☐ Complete ☐ N/A f) Check for consistency with LRDMT ☐ Complete ☐ N/A g) Identify any discrepancies between the system drawing and as-built configuration ☐ Complete ☐ N/A			
Screening Report Review ☐ N/A				
9.	Review realigned components	☐Y ☐N	☐ N/A	☐
	a) Verify consistency between boundary drawings and component list ☐ Complete ☐ N/A			☐
10.	Review in-scope components	☐Y ☐N	☐ N/A	☐
	a) Ensure all generic components are included: anchors, supports, tubing, bolting, insulation, vents, drains, water stops, roof membranes, foundations, etc. ☐ Complete ☐ N/A b) Confirm all LR intended functions are identified ☐ Complete ☐ N/A c) Review material assignments and references ☐ Complete ☐ N/A d) Review for selective leaching components ☐ Complete ☐ N/A e) Review internal and external environment assignments ☐ Complete ☐ N/A f) Verify passive determination (all components listed in NEI 95-10 App. B) ☐ Complete ☐ N/A			☐
11.	Review long-lived components for correct boxes checked ☐ Complete ☐ N/A	☐Y ☐N	☐ N/A	☐
12.	Evaluate problem components and track appropriately ☐ Complete ☐ N/A	☐Y ☐N	☐ N/A	☐
13.	Verify consistency with recent applicant's SER, check for RAI's ☐ Complete ☐ N/A	☐Y ☐N	☐ N/A	☐

Item No.	Review Item	Comment	References Reviewed	Item Complete
14.	Verify consistency with recent applicant's LRA ☐ Complete ☐ N/A	☐Y ☐N	☐ N/A	☐
Aging Evaluation Report Review ☐ N/A				
15.	Verify consistency with GALL ☐ Complete ☐ N/A	☐Y ☐N	☐ N/A	☐
16.	Verify consistency with Wolf Creek SER, check for RAIs ☐ Complete ☐ N/A	☐Y ☐N	☐ N/A	☐
17.	Verify consistency with Wolf Creek AMR ☐ Complete ☐ N/A	☐Y ☐N	☐ N/A	☐
Aging Management Program ☐ N/A				
18.	Review all elements for consistency with GALL ☐ Complete ☐ N/A	☐Y ☐N	☐ N/A	☐
19.	Verify that all items inconsistent with GALL are identified as an exception and a valid technical basis is provided ☐ Complete ☐ N/A	☐Y ☐N	☐ N/A	☐
20.	Verify that all items that are currently not done at DCPP are identified as enhancements and are captured in a procedure mark-up ☐ Complete ☐ N/A	☐Y ☐N	☐ N/A	☐
21.	Verify consistent with NUREG-1800 (SRP) ☐ Complete ☐ N/A	☐Y ☐N	☐ N/A	☐
22.	Verify consistent with recent license renewal RAIs/SERs ☐ Complete ☐ N/A	☐Y ☐N	☐ N/A	☐
23.	Verify that the level of detail is consistent with Palo Verde and the project position for operating experience ☐ Complete ☐ N/A	☐Y ☐N	☐ N/A	☐

This package has been reviewed and is complete (Print/Sign) /____________

Attachment 2, Review Guidance for Engineering Review

The review packages provided to you by the License Renewal Feasibility Study (LRFS) project should contain everything that you require to perform your review. Your review is not intended as an engineering verification review or an independent technical review. The packages you have received for review have been reviewed by the LRFS team, including an Independent Technical Reviewer (ITR), Tien Lee or Sid Bowen, and by David Miklush for technical accuracy. Your review is intended to be a high level review based on your personal knowledge of the system. If during your review you have a question or a comment, you are not expected to do additional research to find the answer. Please provide the comment/question to the LRFS team and they will track down the answer or provide the question to the STARS Center of Business for them to resolve.

Your review should focus on the following items per report or diagrams, as applicable. Some of the review packages will not contain all of these reports or diagrams.

For Scoping Reports:

1) Is the system description, as reflected in the summary, consistent with the CLB?
2) Are there any modifications planned for this system to be implemented before the end of 2009 that you are aware of?
3) Is the system identified correctly as being credited for the five regulated events, e.g. Fire Protection, Station Blackout, Environmental Qualification, Pressurized Thermal Shock, Anticipated Transients Without Scram?

For the Screening Report:

1) Are the materials and environments an appropriate reflection of your system (a list of all the identified environments and materials is located in the beginning of the Aging Evaluation Report, if applicable)?
2) Are any of the components that are screened in for aging management review, short-lived (i.e. replaced on a predetermined schedule on a performance condition that is determined by a PM)?

For the Aging Evaluation Report:

1) Are the aging effects identified for the material and environment combinations appropriate for your system?
2) Are there any other aging effects that have occurred in your system that are not currently identified? If yes, please provide a corrective action document for reference and further research.
3) Are the programs identified for aging management, currently used to monitor system condition?

Attachment 2, Review Guidance for Engineering Review

For the Boundary Diagrams:

1) Is the highlighted portion of your system an appropriate representation of the system boundary that should be in scope for license renewal? (i.e. are all the components required to perform the identified system functions included within the boundary?)
2) Are there special/uniquely credited components on the diagram that is highlighted that should not be, or vice versa?
3) Are all of the safety-related and/or components credited for one of the five regulated events highlighted in green?

For the Aging Management Programs:

Revisions to this report since the last time that you reviewed them have been tracked using the "Track Changes" function in Word.

1) Is the operating experience write up an accurate summary and conclusion for this programs capability to manage aging as it relates to the guidance provided by NUREG-1801? If no, please provide examples of items this program operating experience needs to incorporate.
2) Can DCPP implement the program as described in the elements of the program?

For TLAA Report sections:

Revisions to this report since the last time that you reviewed them have been tracked using the "Track Changes" function in Word.

1. Is the summary description and analysis technically correct?
2. Are there any additional design reports or evaluations that were completed that were not reviewed for this section?

TLAA Section:	Date Issued:	Date Comments Due:	Reviewer(s):

Item No.	Review Item	Comment	References Reviewed	Item Complete
Section Review				
1.	Review section for technical accuracy.	☐Y ☐N	☐ N/A	☐
	d) Is the section consistent with DCPP historical information and future plans? ☐ Complete ☐ N/A b) Verify references ☐ Complete ☐ N/A			
2.	Review section for licensing accuracy.	☐Y ☐N	☒ N/A	☐
	c) Is the section in alignment with DCPP's CLB? ☐ Complete ☐ N/A **d)** Verify references ☐ Complete ☐ N/A			
3.	Review previous applicant examples	☐Y ☐N	☐ N/A	☐
	d) Review other TLAA Reports, if available ☐ Complete ☐ N/A e) Review applicable LRA sections ☐ Complete ☐ N/A f) Review applicable SER sections, checking for RAIs ☐ Complete ☐ N/A			
4.	Which previous applicants' write-up is the section modeled after? ☐ N/A ____________________	☐Y ☐N	☐ N/A	☐
	d) Is the section consistent with industry details and standards? ☐ Complete ☐ N/A e) Review the SER for possible RAIs ☐ Complete ☐ N/A			
5.	a) Verify that the TLAA classification and disposition correct. ☒ Complete ☐ N/A	☒Y ☐N	☒ N/A	☒

This package has been reviewed and is complete (Print/Sign) /____________________________

Diablo Canyon License Renewal Feasibility Study

TR-13DC

Specifications and Standards
License Renewal Feasibility Study Position Paper

Revision 1~~0~~

~~December 1, 2007~~~~April 7, 2009~~January 29, 2010

Specifications and Standards License Renewal Feasibility Study Position Paper
Diablo Canyon Power Plant

Approval Page

Revision	Prepared by:	Reviewed by:	Approved by:
0	Lynnette Fang	Dave Lipinski Jim Johnson	Eric Blocher
Date	May 3, 2007	November 21, 2007	December 01, 2007
1	Stan Shepherd	James Johnson	D.F. Kunsemiller
Date	April 7, 2009	April 7, 2009	January 29, 2010

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Revision Summary

Revision	Required Changes to Achieve Revision	Date
0	Initial Issue	Dec. 01, 2007
1	Incorporated TR PCTF- 046 which clarified pipe support materials, added a new section on bolts/pins and sliding supports, and renumbered the section on Seismic Anchors.	April 7, 2009

TABLE OF CONTENTS

1.0 PURPOSE OF POSITION PAPER

The License Renewal Rule, 10 CFR 54.21(a)(3) (Ref. 6.1), requires that "For each structure and component identified in paragraph (a)(1) of this section, demonstrate that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation." In order to evaluate the applicable aging effects certain aspects of the components design, such as material of construction and operating conditions, must be known.

This position paper identifies the specifications and standards used in the establishment of design criteria for commodity components at DCPP. Commodities used in the context of this position paper refer to components in a system that are procured under a standard plant design specification. The commodity components within the scope of this position paper include:

- Piping
- Valves
- Pipe Supports
- Tubing and Instrumentation
- Tubing and Instrumentation Supports
- Piping Components (including flexible metallic hoses, strainers, filters, fittings, flanges, bolting, fire hose connections and orifices)

2.0 PIPING MATERIAL CLASSIFICATION

The piping material classification (Ref. 6.2) provides design criteria for pipe, flanges, and fittings used in piping systems at DCPP. Piping design information is organized by pipe class (see Section 2.1). Typical design information found under a specific pipe class will be piping system design conditions, piping corrosion allowance (if applicable), piping material, fitting material and end connection type (e.g., bolted, socket weld, butt weld, etc.), flange material and type, applicable valve mark numbers (see Section 3.0), and bolting types and materials.

2.1 Pipe Class

Mechanical system piping at DCPP is grouped by pipe class. To account for the different combinations of classes and codes requirements, a piping symbol classification system, piping Code Classes A to J and @, was developed and used on all piping schematics and drawings to designate piping design, fabrication, erection, and testing criteria. The correlation between the piping symbols and the design, and quality classifications is detailed in Table 1 of Q-List (Ref. 6.3 and Ref. 6.9).

Piping Symbol	Design Class	Quality Class	Applicable Codes and Standards
None	I	I	ASA B31.1 1955
A	I	I	ANSI B31.1-1967
B	I	II	ANSI B31.7 CLASS II-1969 with 1970 Addenda
@	I	II	ANSI B31.1-1967
C	I	III	ANSI B31.7 CLASS III-1969 with 1970 Addenda
D	I	III	ANSI B31.7 CLASS III-1969 with 1970 Addenda
E	II	-	ANSI B31.1-1967
F	II	-	ANSI B31.1-1967 and RG 1.143
G	II	-	ANSI B31.1-1967 and NFPA Standards
Gl	II	-	NFPA Standards
H	II	-	ANSI B31.1-1967 and RG 1.143
J	I	-	ANSI B31.1-1967

Piping Specifications Drawings provide a list of specification alpha-numeric numbers (such as K2 and S2), design pressures and temperatures. The information is used as input to formulate the analysis model for piping stress qualification. Each line on the Piping Schematics and Line Designation Tables is designated with a Piping Specification number. They are controlled drawings.

Drawing No: 049021, 047205 to 0472xx

Based on the specification number, pipe sizes and schedules (thicknesses) and material can be determined from the Mechanical Design Standard (MDS) drawings, No. 047205 through 047295.

The line identification number on the P&ID drawings is formatted as follows:

AA-BBBB-C-DDD

Where:
AA Piping Specification (Drawing 049021)
BBBB Sequence Number
C Line Size (Inches)
DDD Insulation Specification (Drawing 101905)

2.2 Codes and Standards

See Table 4.1-1 of DCM T-25.

2.3 Piping Components

Piping Specifications Drawings provide a list of specification alpha-numeric numbers (such as K2 and S2), design pressures and temperatures. They also provide specifications for piping, fittings, flanges, bolts, nuts, washers, gaskets and tubing. Piping Specifications Index lists all the applicable drawing numbers.

3.0 MASTER VALVE LIST

The Valve Lists are classified by systems. Each OVID system drawing contains a list of all valves in that system. Valves in that system are identified by a unique valve identification number.

3.1 Valve Identification Number

The valve identification number is formatted as follow:

AAA-B-CCC-DDDD

Where:
AAA System Abbreviation
B Unit Number
CCC Type of Valve
DDDD Sequence Number

3.2 Valve Material

The most common valve materials are specified in the following drawings:

1. Drawing 049020, Valve Specification (Ref. 6.12)
2. Drawing 053479, Instrument Valve Specifications (Ref. 6.13)

If the full valve identification number is given, the references associated with this valve can be found in PIMS, sometimes including technical specifications.

4.0 PIPE SUPPORTS

Pipe supports refer to all types of metal supports which are designed to transmit loads from the pressure retaining barrier of the piping to the load carrying building structure, whether concrete or structural steel. The drawings entitled "Pipe Support Drawing List" provide all the pipe support drawing numbers.

- Drawing No. 100796 is for unit 1
- Drawing No. 100821 is for unit 2

The hanger number is formatted as follows:

AA – BBB – T

- T → The Type
- BBB → The sequence within the group
- AA → The hanger group number

Note:

The letters designate the support type. The letters used to designate the support type are (Ref. 6.6):

Type	Description
A	Anchor
CS	Constant Support
G	Guide
R	Rigid or Restraint
SL	Seismic Limiter
V	Variable Spring

4.1 Piping Installation Specifications

Specifications for the fabrication and installation of piping, hangers and supports, valves, specialty and accessory items required for a complete piping system are contained in DCPP documents MP M-56.10 (Ref. 6.4) and MP M-55.5 (Ref. 6.5).

4.2 Pipe Support Materials

4.2.1 Unless specified otherwise, all piping systems are considered to be supported by carbon steel components. All piping systems that include stainless steel pipe will be considered to have stainless steel and carbon steel support components.

4.2.2 Unique situations may require reference to the bill of materials on specific hanger drawings, or other sources, to determine the composition of the supports~~, e.g., CuNi alloy is used in the intake structure at DCPP~~.

4.2.3 Some supports are designed to allow thermal movement of pipe or equipment while maintaining the support function. For these supports, a separate component is included to evaluate the aging effect of LOSS OF MECHANICAL FUNCTION. The material assigned to these components, LUBRITE, includes not only the patented material produced by Lubrite Technologies, but also other slide bearing material such as Fluorogold, Teflon, and graphitic tool steel.

4.2.4 All pins, bolting, and other removable hardware are evaluated with the structural support, except high strength bolts for Class 1 NSSS supports, which are evaluated separately. A separate component for these high strength bolts is included with the material designated as HIGH STRENGTH LOW ALLOY STEEL.

4.3 Seismic Anchors

4.3.1 Restraint direction can be found on the isometrics. For seismic supports, DCPP has hard copies of colored P&IDs which show the stress isometric drawing numbers. The seismic anchors will be identified once the line numbers are provided.

~~4.2.3 Restraint direction can be found on the isometrics. For seismic supports, DCPP has hard copies of colored P&IDs which show the stress isometric drawing numbers. The seismic anchors will be identified once the line numbers are provided.~~

5.0 TUBING AND INSTRUMENTATION INSTALLATION

Instrumentation at DCPP is installed in accordance with the Installation of Instrumentation (DCP -400) (Ref. 6.6). Instrument take-off piping and fittings up to and including the root valve conform to the main piping line specification. Installation details are shown on location drawings and installation details. These drawings are listed in the instrument index (Ref. 6.7) or may be found in PIMS as associated drawings for a particular instrument of interest. Further references to drawings for racks, supports, clamps, level setting, and other miscellaneous details required for installation are included on the location and/or installation detail drawings.

5.1 Instrumentation Installation Specification

The Installation Specification (Ref. 6.7) for Instrumentation and Controls for Equipment for DCPP Units 1&2 establishes methods, standards, and codes to be used during the installation, storage, and handling of instrumentation and control equipment at the DCPP Site, which includes all power block, service, and administration facilities. The equipment installed under this specification includes sensors, transmitters, thermowells, pneumatic signal lines and pneumatic power supplies, sensing lines, instrument valves, racks, panels, control boards, level gauges, computer and all other control room racks, panels, and cabinets.

5.2 Codes and Standards

All instrument materials, fabrication, installation, testing, and examination is in accordance with the Codes and Standards from societies listed below. A detailed list of specific codes and standards from each society are listed in Appendix A.

- American Society of Mechanical Engineers
- American National Standards Institute
- Instrument Society of America

5.3 Tubing Materials

The material used for instrument tubing at DCPP has been selected to satisfy the pressure boundary requirements of GDS Criterion 9. These requirements are further detailed in the ASME B&PV Code, Section III, Subsection NB and in paragraph 122.3 of ASME/ANSI B31.1, 1973, Summer Addendum.

Stainless steel tubing, ASTM A213, Grade TP316 has been selected for most of the instrument tubing at DCPP due to its pressure rating and corrosion resistance characteristics. SA213 Type 304 tubing is used for instrumentation on Pressurizer, Pressure Relief Tank, Pressurizer Surge and selected instrumentation on the RCS lines. (Ref. 6.8) The use of SA213, Type 304 material in these applications has been specifically reviewed and is acceptable in these applications (Ref. 6.14).

These grades of stainless steel are compatible with the chemistry controls in place at DCPP and allow for the use of vendor stock materials for valves and fittings.

Copper tubing ASTM B88 Drawn Temper Type L and Annealed Copper Tube ASTM B88 Type K with associated fittings (Ref 6.15 and Ref. 6.16) are used in pneumatic instrument tubing and some other Design Engineering approved applications (Ref. 17). All tubing in Systems 25 and 26 is copper (ref 6.11).

All vendor supplied tubing is either stainless steel or carbon steel. All tubing not in Systems 25 and 26 and not vendor supplied is stainless steel.

Fitting materials are of ASTM A182 Gr F316, A276 Type 316, A479 Type 316, ASTM A403 GR WP316, or ASME SA-479 Type 316, due to material compatibility with DCPP tubing material and the materials design pressure rating.

Valve materials are as specified per ANSI B31.7 Table 1-724 or ANSI B31.1. These materials were also selected for their compatibility with the tubing material and design pressure rating.

5.4 Tubing and Instrumentation Supports

5.4.1 Unless specified otherwise, tubing and instrumentation supports at DCPP are made from galvanized carbon steel Unistrut in accordance with PG&E drawing 049238 (Ref. 6.8).

5.4.2 Unique situations may require reference to the instrument installation detail drawings and the installation specification for instrumentation and controls (Ref. 6.7) to determine the composition of the supports, e.g., some supports in Containment, at the Intake Structure, and outdoors may use stainless steel Unistrut.

5.4.3 The clips attaching tubing to support members shall be as specified in PG&E drawing 049238 (Ref. 6.8) or as specified by Design Engineering.

6.0 REFERENCES

6.1 10 CFR Part 54 “Requirements for Renewal of Operating Licenses for Nuclear Power Plants”
6.2 DCPP Drawing No. 049021, Rev. N/A, Piping Specification Index
6.3 Table 1 of Q-List, Rev. 25, Relationship of Design and Quality Group Classifications
6.4 MP M-56.10, Rev.16, Piping Fabrication, Installation, Repair or System Alteration
6.5 MP M-55,5, Rev. 12, Pipe Support Removal/Reinstallation procedure
6.6 MIP I-1.0, Rev. 3, Installation of Instrumentation (DCP-400)
6.7 Drawing 102030-2, Rev. 24, Instrument Installation
6.8 Drawing 049238, Rev. N/A, Instrument Tubing Supports
6.9 DCM T-26, Rev. 3A, Pipe Support Analysis
6.10 DCM T-25, Rev. 8, Piping Stress Analysis
6.11 DCPP Interoffice Correspondence titled “DCPP Tubing Specs,” email Lodolo to Albright dated 07/16/2007
6.12 Drawing 049020, Rev. N/A, Valve Specification
6.13 Drawing 053479, Rev. N/A, Instrument Valve Specification
6.14 PG&E Calculation ITS-11, Rev N/A, Instrument Tubing Supports FS-576-425
6.15 Drawing 047207, Rev. N/A, Piping Specification “C”
6.16 Drawing 047208, Rev. N/A, Piping Specification “C-1”
6.17 PG&E Calculation P-I&C-40, Rev. N/A, Seismic Qualification of Instrument Tubing (Copper) Per Drawing 049238.

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Appendix A

American Society of Mechanical Engineers

ASME Boiler and Pressure Vessel Code, Section III - Nuclear Power Plant Components. Refer to DCM T-38 for the applicability of the ASME B&PV code to instrument tubing, valves and fittings.

ASME Boiler and Pressure Vessel Code, Section VIII - Pressure Vessels. Refer to DCM S-25B for the applicability of the ASME B&PV code to backup air system accumulators.

American National Standards Institute

ANSI/ANS-4.5-1980	Criteria for Accident Monitoring Functions in Light-Water-Cooled Reactors This standard is cited in Reg Guide 1.97. PG&E's extent of conformance with this standard is contained in Enclosure 5 of DCL-93-284.
ANSI B31.1	Power Piping Code. ANSI B31.1 is applicable to the design and material selection for instrument tubing, valves and fittings Refer to DCMs S-25B and T-38 for the specific editions that PG&E is committed to.
ANSI B31.7	Nuclear Power Piping, 1969 Edition through 1970 Addenda ANSI B31.7 is applicable to instrument tubing valve material selection. Refer to DCM T-38.
ANSI/IEEE-ANS-7-4.3.2	Application Criteria for Programmable Digital Computer Systems in Safety Systems of Nuclear Power Generating Stations This standard expands and amplifies the requirements of IEEE Std 603-1980.
ANSI N13.1-1969	Guide to Sampling Airborne Radioactive Materials in Nuclear Facilities This standard is cited in Reg Guide 1.97. Refer to DCM S-39.
ANSI N18.2	Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants This standard provides guidance on classification of structures, systems and components.

IEEE Std 100-1988	IEEE Standard Dictionary of Electrical and Electronics Terms This IEEE standard is applicable for its definitions only.
IEEE Std. 279-1971	IEEE Standard: Criteria for Protection Systems for Nuclear Power Generating Stations Diablo Canyon plant protection system meets the requirements for independence and isolation specified in this standard.
IEEE Std. 308-1971	IEEE Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations Diablo Canyon is committed to this standard. It is used as a basis for electrical separation, isolation and redundancy. Refer to DCM T-19.
IEEE Std. 323-1971	Trial-Use Standard: General Guide for Qualifying Class I Electric Equipment for Nuclear Power Generating Stations This standard is applicable for equipment purchased prior to February 22, 1983.
IEEE Std. 323-1974	Standard for Qualifying Class IE Electric Equipment for Nuclear Power Generating Stations This standard is applicable for equipment purchased after February 22, 1983.
IEEE Std. 336-1971	Standard Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations Diablo Canyon meets the intent of IEEE Std. 336. [FSAR 7.2.2.2.8]
IEEE Std. 338-1971	Trial-Use Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems Diablo Canyon meets the intent of IEEE Std. 338. [FSAR Sections 7.2.2.2.5 and 7.3.2.5]
IEEE Std. 344-1971	Trial-Use Guide for Seismic Qualification of Class I Equipment for Nuclear Power Generating Stations Original seismic qualification of equipment was in accordance with IEEE Std. 344-1971. See DCM T-10.

IEEE Std. 344-1975	IEEE Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations Requalification of equipment is performed in accordance with this Reg Guide. Refer to DCM T-10.
IEEE Std. 344-1987	IEEE Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations This standard is applicable to new equipment not previously seismically qualified. Refer to DCM T-10.
IEEE Std. 380-1975	Definition of Terms Used in IEEE Standards on Nuclear Power Generating Stations This IEEE standard is applicable for its definitions only.
IEEE Std. 472-1974	IEEE Guide for Surge Withstand Capability Test Main annunciator system field contact input circuits comply with this standard. Refer to DCM S-43B.
IEEE Std. 497-1977	IEEE Trial-Use Standard Criteria for Accident Monitoring Instrumentation for Nuclear Power Generating Stations This IEEE standard is referenced by Reg Guide 1.97. PG&E is not committed to this standard.
IEEE Std 498-1980	Standard Requirements for the Calibration and Control of Measuring and Test Equipment Used in the Construction and Maintenance of Nuclear Power Generating Stations This standard may be useful for guidance information. However, PG&E is not committed to this standard.
IEEE Std. 603-1980	IEEE Standard Criteria for Safety Systems for Nuclear Power Generating Stations This standard is applicable to the Eagle 21 design, verification and validation plan.
IEEE Std. 627-1980	IEEE Standard for Design Qualification of Safety Systems Equipment Used in Nuclear Power Generating Stations Diablo Canyon equipment qualification meets the intent of this standard. However, PG&E is not committed to this standard.

Instrument Society of America

ISA-S7.0.01-1996	Quality Standard for Instrument Air This standard provides useful information. However, PG&E is not committed to this standard.
ISA-S7.3-1975	Quality Standards for Instrument Air Refer to DCM S-25B for a discussion of the implementation of the requirements contained in ISA-S7.3.
ISA-S51.1-1979	Process Instrumentation Terminology This standard is applicable for its definitions only.
ISA-67.01	Transducer and Transmitter Installation for Nuclear Safety Applications This standard was published subsequent to the original design and construction of Diablo Canyon. It provides prudent design guidance for new plant modifications and maintenance activities.
ISA-S67.02	Nuclear Safety-Related Instrument Sensing Line Piping and Tubing Standards for Use in Nuclear Power Plants This standard was published subsequent to the original design and construction of Diablo Canyon. It provides prudent design guidance for new plant modifications and maintenance activities. Specific criteria within this standard are discussed in Section 4.2.2.4.
ISA-S67.03	Standard for Light Water Reactor Coolant Pressure Boundary Leak Detection This standard provides useful information. However, PG&E is not committed to this standard.
ISA-S67.04	Part I - Setpoints for Nuclear Safety-Related Instrumentation The Diablo Canyon setpoint program is consistent with the intent of this document.
ISA RP67.04	Part II - Methodologies for the Determination of

	Setpoints for Nuclear Safety-Related Instrumentation The Diablo Canyon setpoint program is consistent with the intent of this document.
ISA-S67.06	Response Time Testing of Nuclear Safety-Related Instrument Channels in Nuclear Power Plants This standard provides useful information. However, PG&E is not committed to this standard.
ISA-S67.10	Sample Line Piping and Tubing Standard for Use in Nuclear Power Plants This standard provides useful information. However, PG&E is not committed to this standard.
ISA-S67.14	Qualifications and Certification of Instrumentation and Control Technicians in Nuclear Facilities This standard provides useful information. However, PG&E is not committed to this standard.

Diablo Canyon License Renewal Feasibility Study

TR-12DC

Design Basis Events
License Renewal Feasibility Study Position Paper

Revision 1

January 29, 2010~~09~~

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Design Basis Events License Renewal Feasibility Study Position Paper
Diablo Canyon Power Plant

Approval Page

Revision	Prepared by:	Checked By:	Approved by:	Owner Accepted
0	David Boortz	Gordon Chen Jim Johnson Gary Warner Dave Lipinski	Eric Blocher	--
Date	July 19, 2007	October 29, 2007	December 01, 2007	--
1	Stan Shepherd	D.R. Lipinski	D.F. Kunsemiller	P. R. Soenen
Date	4/2/2009	1/13/2010	1/29/2010	2/5/2010

Revision Summary

Revision	Required Changes to Achieve Revision	Date
0	Initial Issue.	Dec. 01, 2007
1	Incorporated PCTF # 56 which added a description of the Seismically Induced Systems Interaction (SISI) Program at the end of the subsection titled "Vibratory Ground Motion (3.2.1) and Seismic Effects (3.7.1, 3.8)", within Section 3.1.; confirmed that the condenser is not credited in the Steam Generator Tube Rupture analysis; detailed definitions related to 10 CFR 54.4(a)(1); updated discussion related to application of Alternative Source Term methodology. Completed word search for "criteria" vs "class" and removed open item.	April 2, 2009

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1.0 PURPOSE OF POSITION PAPER

Chapters 1 through 12 of the Diablo Canyon Power Plant (DCPP) Updated Final Safety Analysis Report (FSAR) were reviewed to identify design basis events (DBEs) as defined in 10 CFR 50.49(b)(1). Structures, systems, and components (SSCs) that are relied upon to remain functional during and following DBEs to ensure the functions described in 10 CFR 54.4(a)(1) criteria were also identified, as appropriate. Anticipated operational occurrences and postulated accidents described in FSAR Chapter 15 were reviewed separately to identify SSCs and their associated functions as described in 10 CFR 54.4(a)(1). This Position Paper identifies the DBEs identified during the review of Chapters 1 through 12 of the Updated FSAR.

This document is for the use of license renewal feasibility project personnel engaged in the preparation, review, or approval of scoping and screening evaluations in support of license renewal feasibility activities for DCPP.

2.0 DCPP DBE & SAFETY RELATED CLASSIFICATION CONSIDERATIONS

PG&E established its own design criteria and classification requirements for structures, equipment, and systems used in the Diablo Canyon Power Plant because industry and regulatory standards had not yet been developed. It is recognized that during the design and construction of DCPP Units 1 and 2, significant industry and regulatory progress was made in establishing common and agreed upon methods of classification. The newer methods of classification all differ slightly in detail from those for Diablo Canyon, but the form and intent of all are equivalent as shown in the FSAR. (Ref. 4.2, DCPP Q-List)

~~The~~ FSAR Section 3.2.1 provides a description and definitions of the classifications for DCPP ~~Structures, Systems and Components (~~SSCs~~)~~ based on Design Class, Seismic Category~~Class~~ and Quality Group. DCPP specific definitions for design and quality classifications in the FSAR, Q-List, and maintenance rule program are not in-consistent with the definition of safety-related provided in 10 CFR 54.4(a)(1).

Although DCPP current licensing basis (CLB) documents do not explicitly define the term “safety-related”, the FSAR does describe certain SSCs as "safety-related". Guidance for determining the DCPP SSCs required to remain functional in the event of an SSE was provided in AEC Safety Guide (SG) 29. For DCPP, plant features required to perform this function are designated Design Class I.

The exposure guidelines used for DCPP license renewal are the same as 10 CFR 54.4 with the exception of guidelines cited for off-site exposures. In addition to the guidelines of 10 CFR 100, 10 CFR 54.4(a)(iii) references the dose guidelines of 10 CFR 34(a)(1) and 10 CFR 50.67(b)(2). Except for the fuel handling accident analysis, DCPP has not implemented ~~revised~~ the ~~current accident~~alternative source term guidelines of 10 CFR 50.67(b)(2). Therefore, the guidelines of 10 CFR 50.67(b)(2) are applicable only by exception, through specific amendments, under the DCPP CLB. A review of the systems and components that are credited in the fuel handling accident analysis was performed to ensure the applicable systems and components were included in the scope of license renewal. (Ref. 4.6, DCPP License Amendment 163 & 165)

~~and therefore the reference to 10 CFR 50.67(b)(1) as stated in 10 CFR 54.4(a)(1)(iii) is not applicable to DCPP.~~ The reference to 10 CFR 50.34(a)(1) as stated in 10 CFR 54.4(a)(1)(iii) is applicable to applicants for a construction permit, a design certification or combined license pursuant to 10 CFR 52 and does not apply to DCPP.

DCPP SSC functions are consistent with the DCPP CLB and consider the following DBEs:

- Design basis accidents
- Seismic events
- External events such as ice effects, floods, earthquakes, tornado/wind loading,
- Internal events such as high energy line breaks, flooding, missiles, fires

2.1 DCPP DEFINITION OF SAFETY-RELATED DESIGN/QUALITY CLASSIFICATIONS

The following DCPP Q-List definition of Design Class 1 (safety related) is consistent with the FSAR definition with the additional requirement to be designed to withstand the safe shutdown earthquake (SSE) and remain functional.

> "Appendix A to 10 CFR 100 requires that structures, systems, and components necessary to assure:
>
> (1) the integrity of the reactor coolant pressure boundary
>
> (2) the capability to shut down the reactor and maintain it in a safe shutdown condition, or
>
> (3) the capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to listed exposure guidelines,.."
>
> ~~be designed to withstand the safe shutdown earthquake (SSE) and remain functional."~~

Procedure CF3.ID19 establishes how SSCs for DCPP are classified and how changes to the Q-List are controlled. The procedure requires that all non-editorial changes to the contents of the Q-List be reviewed pursuant to the requirements of 10 CFR 50.59. Q-List classification is consistent with the DCPP Current Licensing Basis.

The FSAR Section 3.2.1 provides a description and definitions of the classifications for DCPP SSCs based on Design Class, Seismic Category, and Quality Group. DCPP specific definitions for design and quality classifications in the FSAR, Q-List, and maintenance rule program are not in-consistent with the definition of safety-related provided in 10 CFR 54.4(a)(1).

The following are terms and classification de~~finitions~~scriptions as used in DCPP procedures and CLB documents.

Safety-Related

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DCPP procedure MA1.ID17, Maintenance Rule Monitoring Program, Section 5.1.1 defines Safety-Related as those SSCs that are to remain functional during and after a design basis event to ensure reactor coolant pressure boundary integrity, capability to shutdown the reactor and monitor safe shutdown conditions, or capability to prevent or mitigate the consequences of accidents comparable to 10 CFR Part 100 guidelines.

Design Class I

DCPP FSAR Table 3.2-1 defines Design Class I as the plant features important to safety, including plant features required to assure: (1) the integrity of the reactor coolant pressure boundary, (2) the capability to shut down the reactor and maintain it in a safe shutdown condition, or (3) the capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to the guideline exposures of 10 CFR 100.

QA Class 'Q'
The DCPP Q-List defines QA Class 'Q' as, "Equipment and structures to which the QA provisions of Appendix B to 10 CFR 50 apply for design, procurement, and construction." Table 1 of the Q-List shows that all SSCs designated as 'Q' are also Design Class I.

QA Class 'S'
SSCs important to reactor operation but not essential to safe shutdown and isolation of the reactor, and failure of which would not result in the release of substantial amounts of radioactivity, are classified as Design Class II. SSCs not related to reactor operation or safety are classified as Design Class III. Certain Design Class II and III SSCs have seismic qualification requirements and may be designated as Seismic Category I; these SSCs are designated as QA Class 'S'. (Ref. 4.1, DCPP FSAR, Table 3.2-2, Note 1)

Seismic Category I
Seismic Category I SSCs are designed to remain functional during the design basis earthquakes that they are required to withstand. All plant features designated as Design Class I are also Seismic Category I. Design Class II features may or may not be Seismic Category I. (Ref. 4.1, DCPP FSAR, Section 3.2.1)

~~2.1~~2.2 LICENSE RENEWAL SCOPING CRITERIA

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License Renewal Scoping Criteria 10 CFR 54.4(a)(1)
The functions described in 10 CFR 54.4(a)(1) shall be maintained during design events as described in 10 CFR 50.49(b)(1). Design basis events are defined in 10 CFR 50.49(b)(1) as conditions of normal operation, including anticipated operational occurrences, design basis accidents, external events, and natural phenomena for which the plant must be designed to ensure the following functions:

- The integrity of the reactor coolant pressure boundary;
- The capability to shut down the reactor and maintain it in a safe shutdown condition; or

- The capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures comparable to the guidelines in § 50.34(a)(1), § 50.67(b)(2), or § 100.11 of this chapter, as applicable.

~~DCPP has not revised the current accident source term in accordance with 10 CFR 50.67 and therefore the reference to 10 CFR 50.67(b)(1) as stated in 10 CFR 54.4(a)(1)(iii) is not applicable to DCPP. The reference to 10 CFR 50.34(a)(1) as stated in 10 CFR 54.4(a)(1)(iii) is applicable to applicants for a construction permit, a design certification or combined license pursuant to 10 CFR 52 and does not apply to DCPP.~~

As discussed in Section ~~2.2 below,~~2.1 above, in DCPP's documentation, the terms Design Class I and Safety-Related are essentially equivalent, and all SSCs designated as 'Q' are also Design Class I. Therefore, SSCs identified as Design Class I, Safety-Related, or QA Class 'Q' are treated as Safety-Related and ~~all SSCs designated as Safety Related, Design Class 1, or Q~~ are within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1).

All Seismic Category I SSCs designated as **QA Class 'Q' are treated as Safety-Related and** are within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1). All Seismic Category I SSCs designated as QA Class 'S' are **evaluated for potential interactions with Safety-Related SSCs** and are within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(2).

~~2.2DCPP DEFINITION OF SAFETY-RELATED DESIGN/QUALITY CLASSIFICATIONS~~

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~~"PG&E established its own design criteria and classification requirements for structures, equipment, and systems (SSC) used in the Diablo Canyon Power Plant because industry and regulatory standards were not developed. It is recognized that during the design and construction of DCPP Units 1 and 2, significant industry and regulatory progress was made in establishing common and agreed upon methods of classification. The newer methods of classification all differ slightly in detail from those for Diablo Canyon, but the form and intent of all are equivalent as shown in the FSAR." (Ref. 4.2, DCPP Q-List)~~

~~The following are terms and classification definitions as used in DCPP procedures and CLB documents.~~

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~~Safety-Related~~

~~DCPP procedure MA1.ID17, Maintenance Rule Monitoring Program, Section 5.1.1 defines safety related as those SSCs that are to remain functional during and after a design basis event to ensure reactor coolant pressure boundary integrity, capability to shutdown the reactor and monitor safe shutdown conditions, or capability to prevent or mitigate the consequences of accidents comparable to 10 CFR Part 100 guidelines.~~

~~Design Class 1~~

~~DCPP FSAR Table 3.2-1 defines Design Class 1 as the plant features important to safety, including plant features required to assure: (1) the integrity of the reactor coolant pressure boundary, (2) the capability to shut down the reactor and maintain it in a safe shutdown condition, or (3) the capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to the guideline exposures of 10 CFR 100.~~

~~QA Class 'Q'~~
~~The DCPP Q-List defines QA Class 'Q' as, "Equipment and structures to which the QA provisions of Appendix B to 10 CFR 50 apply for design, procurement, and construction." Table 1 of the Q-List shows that all SSCs designated as 'Q' are also Design Class 1.~~

~~QA Class 'S'~~
~~FSAR Table 3.2-2, Note (l) states, "Certain Design Class II and III SSCs have seismic qualification requirements and may be designated as Seismic Category I; these SSCs are designated as QA Class 'S'.~~

~~Seismic Category I~~
~~DCPP FSAR Section 3.2.1 states that all plant features designated as Design Class I are also Seismic Category I. Design Class II features may or may not be Seismic Category I~~
~~FSAR~~
~~Section 3.2.1 and Table 3.2-1 of the DCPP FSAR identifies Design Class I as those plant features important to safety. Plant features important to safety include those necessary to assure (a) the integrity of the reactor coolant pressure boundary, (b) the capability to shut down the reactor and maintain it in a safe shutdown condition, or (c) the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures comparable to the guideline exposures of 10 CFR 100. (Ref. 4.1 Table 3.2-1)~~

~~Q-List~~
~~The following DCPP Q-List definition of Design Class 1 (safety related) is consistent with the FSAR definition with the additional requirement to be designed to withstand the safe shutdown earthquake (SSE) and remain functional.~~

> ~~"Appendix A to 10 CFR 100 requires that structures, systems, and components necessary to assure:~~
>
> ~~(1) the integrity of the reactor coolant pressure boundary~~
>
> ~~(2) the capability to shut down the reactor and maintain it in a safe shutdown condition, or~~
>
> ~~(3) the capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to listed exposure guidelines,~~
>
> ~~be designed to withstand the safe shutdown earthquake (SSE) and remain functional." (Ref. 4.2)~~
>
> ~~"Guidance for determining the DCPP structures, systems, and components required to remain functional in the event of an SSE was provided in AEC Safety Guide 29. For DCPP, plant features required to perform this function are designated Design Class I." (Ref. 2)~~

~~Procedure CF3.ID19 establishes how structures, system, and components (SSCs) for DCPP are classified and how changes to the Q-List are performed. Q-List classification is consistent with the DCPP FSAR Section 3.2 and the DCPP Licensing Basis.~~

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~~Maintenance Rule~~
~~Section 5.1 of the Maintenance Rule Monitoring Program procedure MA1.ID17, indicates 10 CFR 50.65 Section (b)(1) requires that the scope of the Maintenance Rule monitoring program include "Safety related structures, systems, or components that are relied upon to remain functional during and following design basis events..." (Ref. 4)~~

- ~~Those SSCs that are to remain functional during and after a design basis event to ensure reactor coolant pressure boundary integrity, capability to shutdown the reactor and monitor safe shutdown conditions or capability to prevent or mitigate the consequences of accidents comparable to 10 CFR Part 100 guidelines are considered "in-scope."~~

- ~~Identification of the safety related SSCs should be derived principally from the Q-List. The system Design Criteria Memorandum (DCM) should also be consulted, when available, for the SSC safety related determination.~~

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3.0 DESIGN BASIS EVENTS

The following events are identified in the Diablo Canyon Final Safety Analysis Report chapters other than Chapter 15. The applicable DCPP FSAR sections(s) are listed next to the event in parenthesis. These design basis events were reviewed, with attention paid to the additional equipment, beyond that necessary to respond to a Chapter 15 event.

- Local Meteorological Conditions for Design and Operating Bases (2.3.1.3, 2.3.2.2.1, and 2.3.2.2.2)
- Probable Maximum Flood (2.4.3), Flooding from Storm Runoff (2.4.10), & Flood Protection (3.4)
- Tsunami Flooding (2.4.6.6), Flood Waves (2.4.2.2.2)
- Vibratory Ground Motion (3.2.1) and Seismic Effects (3.7, 3.8)
- Leaks From Other than Radioactive Waste Systems (Table 3.2.1, Footnote)
- Wind and Tornado Loading (3.3)
- Missile Effects (3.5.1)
- Protection Against the Dynamic Effects Associated With the Postulated Rupture of Piping (3.6)
- Control Room Inaccessibility (3.1.4, 7.4)
- Anticipated Transients Without Scram – ATWS (4.3.1.7, 7.6.1.4, 7.6.2.4)
- Stuck Rod (4.3.2.4.9, 4.3.2.5.2)
- RCS Overpressure Design Basis (5.2.2, 5.2.2.1)
- Low Temperature Overpressure Transients (5.2.2.4)
- Rupture of Steam Supply to Turbine-Driven AFW Pump (6.5.3.4)
- Loss of Offsite Power (8.2.2)
- Station Blackout (8.3.1.6)
- Accidental Criticality - New Fuel and Spent Fuel Racks (9.1.1.1, 9.1.2.3)
- Excessive Temperature Low Water Level, or Drainage in the Spent Fuel Pool (9.1.3.1.2, 9.1.3.3.1, 9.1.3.3.2)
- Fuel and Heavy Load Handling Accidents (9.1.2.3, 9.1.4.3)
- Loss of Compressed Air System (9.3.1.3)
- Loss of Ventilation/Habitability of Control Room (9.4.1.2, 9.4.1)

- Fire Within the Plant (9.5.1)
- Failure of the Main Condenser (10.4.1, 10.4.1.3)
- Flooding From the Circulating Water System (10.4.5.4)
- Steam Generator Blowdown Line Break (10.4.8, 10.4.8.3)
- Rupture of Condensate and Feedwater Chemical Injection Tanks (10.4.9)

Malfunctions, Accidents, or other unusual events that could physically damage ESFAS components or could cause environmental changes are listed below. The FSAR Update sections noted within each item present discussions on the provisions to retain the necessary protective action. (7.3.1.2)

- LOCA (see sections 15.3.1, 15.3.4 and 15.4.1)
- Steam Breaks (see sections 15.3.2 and 15.4.2)
- Earthquakes (see sections 2.5, 3.2, 3.7, and 3.8)
- Fire (see section 9.5.1)
- Explosion (hydrogen buildup inside containment see section 15.4)
- Missiles (see section 3.5)
- Flood (see section 2.4 and 3.4)
- Wind (see section 3.3)

The following events do not constitute a hazard to DCPP: (2.2.3)

- Equipment and materials transported by state and local highways. (2.2.1)
- Equipment and materials transported by rail. (2.2.1)
- Equipment and materials transported by ship. (2.2.1)
- Equipment and materials transported by aircraft. (2.2.1)
- Collision of shipping vessels with safety-related structures. (2.2.1)
- Military equipment, vehicles, and weapons. (2.2.1)
- Coastal Liquid Spills (2.2.1)
- Products and materials manufactured or stored in the vicinity. (2.2.2)

The following conditions and events are not applicable to DCPP:

- Explosion of fires from off site Sources (2.2.3)
  - Explosive or combustible materials stored within 5 miles of the site.
  - Natural gas or other pipelines within 5 miles of the site.
- Structures whose collapse could potentially damage SSCs important to safety. (2.2.3)
- Severe weather, such as tornadoes, ice storms, thunderstorms and hail. (2.3.1.3)
- Sea waves generated by dam failures inside or outside the watershed. (2.4.4)
- Surge and Seiche Flooding (2.4.5.3)
- Ice flooding. (2.4.7)
- Cooling water system canals or reservoirs. (2.4.8)
- Low flow due to upstream diversions of rivers. (2.4.9)
- Low water, from tsunami drawdown coincident with low tide and short-period storm waves. (2.4.11 and 2.4.6)
- Surface Faulting 2.5.1.1.2.1)
- Chlorine Gas Release (9.4.1.2)

3.1 DBE SUMMARY DISCUSSION

Review of non-chapter 15 FSAR design basis events for additional SSCs in the scope of license renewal

Local Meteorological Conditions for Design and Operating Bases (2.3.1.3, 2.3.2.2.1, and 2.3.2.2.2)
The annual mean number of days with severe weather conditions, such as tornadoes and ice storms at west coast sites, is zero. Thunderstorms and hail are also rare phenomena, the average occurrence being less than three days per year.
The maximum recorded precipitation in the San Luis Obispo region is 2.35 inches in 1 hour at the DCPP site, and 5.98 inches in 24 hours at San Luis Obispo. The 24 hour maximum and the 1 hour maximum occurred on March 4, 1978. The highest recorded peak gust at Station E is 84 mph, and the maximum recorded hourly mean wind speed is 54 mph, both recorded at the 76-m level of the primary tower. The highest and lowest hourly temperatures recorded at the Diablo Canyon site through the year 2000 were 97°F in October 1987 and 33°F in December 1990, respectively.

Probable Maximum Flood (PMF) (2.4.3), Flooding Protection Requirements (2.4.10), Flood Protection (3.4.4)
The only stream on the site subject to a PMF study is Diablo Creek. The creek collects runoff from a drainage area of 5.19 square miles up from the ocean side.

The PMF was obtained by deriving an estimated probable maximum precipitation (PMP) with a duration of 24 hours over the subject drainage area. The most severe antecedent condition of ground wetness favorable to high flood runoff was assumed. In view of the low elevation of the site, snowmelt was not considered in the study.

It was assumed that during a PMF all culverts are plugged, and water is impounded to the crest of the lowest depression of the switchyard's fill. The artificial reservoir formed in this assumption is so small that the PMF could not affect the plant.

The potential storage of water upstream of the switchyard fill described in DCPP FSAR Section 2.4.3.4 poses no flood threat since the switchyard fill is more than five times as wide as it is deep and the maximum storage of 1100 acre-feet has a face depth of 120 feet.

The site arrangement, with the plant situated on a coastal terrace 85 feet above MSL, virtually eliminates all risks from flooding.

Roofs of safety-related buildings have a drainage system designed in accordance with the Uniform Plumbing Code for an adjusted regional PMP of 4 inches/hour. In addition, overflow scuppers are provided in parapet walls at roof level to prevent ponding of accumulated rainwater in excess of drain capacity. Yard areas around safety-related buildings are graded to provide positive slope away from buildings. Storm runoff is overland and unobstructed. It is, therefore, not possible for ponding from local PMP to flood safety-related buildings.

Safety-related structures, components, and equipment are designed to withstand the effects of potential flooding, as required by GDCs 2 and 4.

The discussion in DCPP FSAR Section 2.4 demonstrates that Diablo Creek is adequate to handle the probable maximum flood (PMF), and that yard and roof drainage designs are such that it is not possible to develop sufficient ponding to flood safety-related buildings. Thus, the depth of water at the plant location for the PMF is zero.

The intake structure is designed with an elevated air intake so that the Design Class I auxiliary saltwater pumps can operate during the design combination tsunami-storm wave runup to elevation +48 feet mean low-low water (MLLW) (+45.4 feet mean sea level (MSL)). These pumps are located below elevation zero feet MSL. The pumps are mounted at a nominal floor elevation -2.1 feet MSL, and each pump is housed in a separate watertight compartment.

Tsunami Flooding (2.4.6.6) Floodwaves (2.4.2.2.2)
The ASW pumps are protected against flooding for the maximum wave height under tsunami and storm wave conditions even if the entire length of the breakwater were degraded to Mean Lower-Low Water (MLLW). Since there is no assurance that the breakwater would not degrade below MLLW, even though this is very unlikely, the DCPP Equipment Control Guidelines include requirements to monitor the condition of the breakwater, to implement corrective action when limited damage is sustained, and to identify the limiting condition for operation relative to the configuration of the breakwaters.

Vibratory Ground Motion (3.2.1) and Seismic Effects (3.7.1, 3.8)
Criterion 2 of the July 1967 GDC and Appendix A to 10 CFR 100, Seismic and Geologic Siting Criteria for Nuclear Power Plants require that nuclear power plant SSCs important to safety be designed to withstand the effects of earthquakes. The Safe Shutdown Earthquake (SSE) is defined as the maximum vibratory ground motion at the plant site that can be reasonably predicted from geological and seismic evidence. The Operating Basis Earthquake (OBE) is that earthquake which, considering the local geology and seismology, can be reasonably expected to occur during the plant life. The SSE of Appendix A to 10 CFR 100 is equivalent to the DCPP double design earthquake (DDE). Similarly, OBE of Appendix A to 10 CFR 100 is equivalent to the DCPP Design Earthquake (DE).

DCPP's capability to withstand a postulated Richter magnitude 7.5 earthquake centered along an offshore zone of geologic faulting known as the "Hosgri Fault" has been reviewed. Guidance for determining the SSCs designed to remain functional in the event of an SSE is provided in Staff Guidance (SG) 29. These plant features, including their foundations and supports, are designated as Seismic Category I in SG 29. DCPP SSCs and their seismic design classifications comply with the intent of SG 29

Appendix A to 10 CFR 100 requires that all nuclear power plants be designed so that, if the SSE occurs, all structures and components important to safety remain functional. Plant features important to safety are those necessary to ensure (a) the integrity of the reactor coolant pressure boundary, (b) the capability to shut down the reactor and maintain it in a safe shutdown condition, or (c) the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures comparable to the guideline exposures of 10 CFR 100.

Plant features that correspond to Seismic Category I, as identified in SG 29, are designed to remain functional during the design basis earthquakes that they are required to withstand: the DE (equivalent to the OBE of SG 29), the DDE (equivalent to the SSE of SG 29), and/or the postulated Hosgri earthquake (HE). The Hosgri Event is a postulated Richter magnitude 7.5 earthquake centered along an offshore zone of geologic faulting, generally referred to as the Hosgri Fault Design Class I plant features are designed to maintain their structural integrity in the event of both the DE/DDE and HE.

PG&E developed and implemented a program to reevaluate the seismic design bases used for the Diablo Canyon Power Plant know as the Long Term Seismic Plan (LTSP). The LTSP contains extensive databases and analyses that update the basic geologic and seismic information in this FSAR Update. However, the LTSP material does not alter the design bases for DCPP. In SSER 34 the NRC states, “The Staff notes that the seismic qualification basis for Diablo Canyon will continue to be the original design basis plus the Hosgri evaluation basis, along with associated analytical methods, initial conditions, etc.”

PG&E committed to the NRC that certain future plant additions and modifications, as identified in that letter, would be checked against insights and knowledge gained from the LTSP to verify that the plant margins remain acceptable.

U.S.N.R.C. Regulatory Guide 1.29, "Seismic Design Classification," provides guidance for identifying and classifying structures, systems, and components which should be seismically qualified. Among other things, the Regulatory Guide specifies that nonsafety-related structures, systems, and components (SSCs) should be seismically designed if their failure could jeopardize the functioning of safety-related components in a seismic event. As a condition for issuance of the Operating Licenses (OLs) for DCPP, PG&E implemented the Seismically Induced Systems Interaction (SISI) Program to address this issue. The SISI Program was a condition imposed on the OLs for DCPP because they had not committed to R.G. 1.29. The objective of the SISI Program is to ensure that SSCs required for safe shutdown of the plant as well as certain accident mitigating systems will not be impaired from performing their safety function as a result of seismically induced interactions when subjected to a seismic event of severity up to and including the postulated 7.5M Hosgri event. Per DCPP DCM T-14, Section 1.1, the SISI Program ensures that targets (SSCs required for safe shutdown of the plant as well as certain accident mitigation systems) will not be impaired from performing their intended safe shutdown/accident-mitigating functions as a result of such interactions with sources (all non-target-related SSCs).

Leaks From Other Than Radioactive Waste Systems (Table 3.2.1, Footnote)
Systems, Structures, and Components (SSCs), including their foundations and supports, that have been classified as Design Class I and designed to remain functional in the event a DDE or HE occurs, and to which the requirements of the Quality Assurance Program apply those portions of systems (other than the radioactive waste management systems) that contain or may contain radioactive material and whose postulated failure could result in conservatively calculated potential offsite exposures in excess of 0.5 rem whole body (or its equivalent to

parts of the body) at the site boundary or beyond are designated as Seismic Category I and shall be designed to withstand the effects of the SSE and remain functional.

Wind and Tornado Effects (3.3)
All seismic Design Class I structures exposed to wind forces are designed to withstand the effects of the design wind, as required by GDC 2. Although a tornado design criterion was not required for the granting of construction permits, the tornado resisting capabilities of Design Class I structures and certain other structures have been reviewed. The design wind specified has a velocity of 80 mph based on a recurrence interval of 100 years and is in accordance with "New Distribution of Extreme Winds in the United States."

Missile Effects (3.5.1)
Structures, shields, and barriers that are designed to withstand missile effects include: (a) accident/incident-generated missiles inside and outside the containment; (b) environmental load (or tornado) generated missiles; and (c) site proximity missiles from industrial, transportation, and military facilities. All of these structures, shields, and barriers are included within the scope of license renewal. (3.5.1)

The recommendations of Regulatory Guides 1.13 and 1.115 as they pertain to internally and externally generated missiles are met. The response to Regulatory Guide 1.14 and Regulatory Guide 1.27 in regard to missiles is included in DCPP FSAR Appendix 3A. DCPP FSAR Appendix 3B provides an evaluation of the effect of postulated missiles generated within the plant.

For missiles generated within the containment, the principal design bases are that missiles generated coincident with a Loss of Coolant Accident (LOCA) shall not cause loss of function of any engineered safety feature (ESF) or loss of containment integrity. The systems located outside the containment structure have been reviewed to determine the possible sources and consequences of missiles. Catastrophic failure of pressure vessels and system piping outside the containment structure is not considered credible as a source of missiles because of the conservative design, material characteristics, and inspection during erection, and prudent operation.

Protection Against the Dynamic Effects Associated With the Postulated Rupture of Piping (3.6)
Special measures have been taken in the design and construction of the plant to protect the public against the consequences of dynamic effects associated with postulated piping ruptures both inside and outside the containment. The plant is designed so that a postulated piping failure will not cause the loss of needed functions of safety-related systems and structures, and so that the plant can be safely shut down in the event of such failure. For moderate energy systems, protection from the jet spray and flooding effects due to critical cracks is incorporated into the design.

Control Room Inaccessibility (3.1.4, 7.4)
The plant is provided with a centralized control room common to both units that contain the controls and instrumentation necessary for operation of both units under normal and accident

conditions. Provisions are made to enable plant operators to readily shut down and maintain the plant at hot shutdown by means of controls located outside the control room.

The primary instrumentation and control functions required for shutdown are located on the hot shutdown remote control panel, in addition to being available in the control room, and are provided for the purpose of achieving and maintaining a safe shutdown in the event that an evacuation of the control room is required. These controls and the instrumentation channels, together with the equipment and services that are available for both hot and cold shutdown, identify the potential capability for cold shutdown of the reactor, subsequent to a control room evacuation, through the use of suitable procedures.

Anticipated Transients Without Scram (4.3.1.7, 7.6.1.4, & 7.6.2.4)
Each Unit has installed an ATWS mitigation system actuation circuitry (AMSAC) system. The AMSAC system is independent and diverse from the reactor protection system. The AMSAC system trips the turbine, starts auxiliary feedwater, and isolates steam generator blowdown on coincidence of low-low steam generator water level in three out of four steam generators. This meets the requirements of 10 CFR 50.62.

The AMSAC system performs an important safety function if the plant's primary reactor protection system fails. Accordingly, to ensure the reliability of the system, all activities that could affect the quality of nonsafety-related AMSAC equipment shall be controlled as if the equipment were safety-related.

Stuck Rod (4.3.2.4.9, 4.3.2.5.2)
Design Criterion 44, "Emergency Core Cooling Systems Capability" (ECCS) requires at least two emergency core cooling systems, preferably of different design principles, each with a capability for accomplishing abundant emergency core cooling, shall be provided. For any rupture of a steam pipe and the associated uncontrolled heat removal from the core, the ECCS adds shutdown reactivity so that with a stuck rod, no offsite power, and minimum ESF, there is no consequential damage to the primary system and the core remains in place and intact. DCPP is provided with the means of making and holding the core subcritical under any anticipated conditions and with appropriate margin for contingencies. These means are discussed in detail in DCPP FSAR Chapters 4.0 and 9.0

RCS Overpressure Design Basis (5.2.2, 5.2.2.1)
The overpressure protection upper limit is based on the positive surge of the reactor coolant produced as a result of turbine trip under full load, assuming the core continues to produce full power and normal feedwater is maintained. The self-actuated safety valves are sized on the basis of steam flow from the pressurizer to accommodate this surge at a setpoint of 2500 psia and a total accumulation of 3 percent. Each of the safety valves is rated to carry 420,000 lb/hr, which is greater than one-third of the total rated capacity of the system. Note that no credit is taken for the relief capability provided by the PORVs during this surge.

The spray nozzles are located on the top of the pressurizer. Spray is initiated when the pressure controlled spray demand signal is above a given setpoint. The spray flow increases proportionally with increasing pressure and pressure error until it reaches a maximum value.

Protection against overpressurization during low temperature operation is provided by the low temperature overpressure protection.

The pressurizer is equipped with three PORVs that limit system pressure for a large power mismatch and thus prevent actuation of the fixed high-pressure reactor trip. The relief valves are operated automatically or by remote-manual control. The operation of these valves also limits the undesirable opening of the spring-loaded safety valves. Remotely operated block valves are provided to isolate the PORVs if excessive leakage occurs. The relief valves are designed to limit the pressurizer pressure to a value below the high-pressure trip setpoint for all design transients, up to and including, the design percentage step load decrease with steam dump but without reactor trip.

In the event of a complete loss of heat sink, protection of the RCS against overpressure is afforded by pressurizer and steam generator safety valves along with any of the following reactor trip functions:

(1) Reactor trip on turbine trip
(2) Pressurizer high-pressure reactor trip
(3) Overtemperature ΔT reactor trip
(4) Steam generator low-low water level reactor trip

<u>Low Temperature Overpressure Transients (5.2.2.4)</u>
RCS overpressure protection during startup and shutdown is provided by the Low Temperature Over Pressure (LTOP) system, which consists of two mutually redundant and independent systems. Each system receives reactor coolant pressure and temperature signals. When a low-temperature, high-pressure transient occurs, it opens a pressurizer PORV until the pressure returns to within acceptable limits. During normal operation, the system is off. If the reactor coolant temperature is below the low temperature setpoint and the enable switch on the main control board is not in the enable position, an alarm will sound on the main annunciator. The operator can then enable the circuit before a water-solid condition is reached, and the system is then ready to operate without further operator action.

The LTOP system relieves the RCS pressure transient given a single failure. Since the two LTOP systems are mutually redundant and independent, failure of either one would not affect the remaining system.

<u>Rupture of Steam Supply to Turbine-Driven AFW Pump (6.5.3.4)</u>
An unisolated double-ended rupture of a turbine driven auxiliary feedwater pump steam supply line (downstream of the non-return valves associated with steam supply isolation valves, FCV-37/38, and upstream of steam supply stop valve, FCV-95, and in the GE/GW area) could result in loss of all auxiliary feedwater (AFW) and main feedwater. A break in this location will result in a reactor trip (automatic or manual), which also trips the Main Feedwater Pumps causing loss of main feedwater. The postulated break will render the turbine driven AFW pump No. 1 inoperable due to loss of steam supply. The resulting increased temperature in the GE/GW area would cause the E/H actuated LCVs associated with motor driven AFW pump No. 3 to fail due to a harsh environment. AFW pump No. 3 is assumed to be lost due to either pump runout/trip on overcurrent due to excessive

flow/insufficient back pressure through the affected AFW flow control valve due to the line break; or by the requirement to isolate AFW feedwater flow to the ruptured S/G within 10 minutes. If S/G 3 is faulted by the break, the single failure of motor driven AFW pump No. 2 would then leave the plant with no AFW.

To ensure that the plant is maintained within it analyzed conditions, either the steam line break must be isolated or LCV-113 and LCV-115 associated with AFW pump No. 3 must be capable of operating throughout the transient in a harsh environment.

Loss of Offsite Power (8.2.2)

The 230-kV system is the immediate source of offsite power following a design basis accident or unit trip. Operability is based on the ability to transfer to the 230-kV system following a design basis accident or unit trip without loading the emergency diesel generators, and provide adequate voltages to the safety related loads. Load flow and dynamic loading analyses are performed for anticipated configurations of the transmission network (e.g., generating units out of service, transmission line(s) out of service, or voltage control devices out of service) to ensure that the 230-kV system has sufficient capacity and capability to operate the engineered safety features for a design basis accident (or unit trip) on one unit, and those systems required for an orderly shutdown of the second unit. A dual-unit trip is not a licensing or design basis requirement.

For postulated design-basis events, the transmission system is assumed to be in steady state. Any external condition affecting the transmission network is assumed to occur in sufficient time prior to the transfer to the 230-kV system such that the voltage on the 230-kV/12-kV LTC has adjusted to the transient, and PG&E's Transmission Operations Center has restored the DCPP 230-kV switchyard voltage to meet or exceed the minimum scheduled pre-trip voltage.

Station Blackout (8.3.1.6)

The DCPP Station Blackout (SBO) analysis was performed using the guidance provided in NUMARC 87-00, Rev. 0. Using this guidance, the coping time (the postulated maximum SBO duration) for DCPP was determined to be 4 hours. During an SBO event, the SBO analysis demonstrated that the plant could be safely shutdown utilizing either Buses G or H and their normally connected EDGs (Emergency AC (EAC) sources) and, thereby, the third EDG and its Bus F were declared the Alternate AC (AAC) source. However, during an SBO event, any of the three EDGs may be used as the AAC source. The SBO analysis takes credit for the hydraulic interconnection of the ASW systems between Unit 1 and 2 by manually opening FCV-601. Since the AAC source is a Class 1E EDG, it meets the criterion for the AAC source to be available within 10 minutes and, therefore, no coping analysis was required to be performed.

Accidental Criticality - New Fuel and Spent Fuel Racks (9.1.1.1, 9.1.2.3)

The fuel storage and handling systems comply with the criticality accident requirements of 10 CFR 50.68(b), "Criticality Accident Requirements," in lieu of maintaining a monitoring system capable of detecting a criticality as described in 10 CFR 70.24, "Criticality Accident Requirements." In accordance with 10 CFR 50.68(b)(6), radiation monitors are provided in storage and associated handling areas when fuel is present to detect excessive radiation levels and to initiate appropriate safety actions.

New fuel will be stored in racks in vaults in the fuel handling area of the auxiliary building, located as shown in DCPP FSAR Figure 9.1-1, or in the spent fuel racks. The racks are designed to store, protect, and prevent criticality of new fuel assemblies until used within the reactor The fuel storage criticality analysis assumed the new fuel vault was completely filled with 5.0 weight percent U-235 fuel with no credit taken for any burnable absorber that may be present in the fuel assemblies (e.g., integral fuel burnable absorber, IFBA). Although the new fuel vault is normally dry, two accident scenarios were considered as part of the vault's design bases: (1) when fully flooded with unborated water, a $k_{eff} \leq 0.95$ must be maintained after allowing for calculational uncertainties, and (2) when flooded with aqueous foam, a $k_{eff} \leq 0.98$ must be maintained after allowing for calculational uncertainties.

The Spent Fuel Pools (SFPs) are designed to accommodate both new and spent fuel assemblies in a subcritical array such that a $k_{eff} < 1.0$ is maintained if flooded with unborated water. The spent fuel storage racks are designed in accordance with Safety Guide 13 and the ASME Boiler and Pressure Vessel Code, DCPP FSAR Section III, Subsection NF. In accordance with 10 CFR 50.68(b)(4), the high density spent fuel storage racks are designed to ensure that, with credit for soluble boron and with fuel of the maximum fuel assembly reactivity, a K_{eff} of less than or equal to 0.95 is maintained, at a 95 percent probability, 95 percent confidence level, if the racks are flooded with borated water, and a K_{eff} off less than 1.0 is maintained, at a 95 percent probability, 95 percent confidence level, if the racks are flooded with unborated water.

<u>Excessive Temperature, Low Water, or Drainage in the Spent Fuel Pool (9.1.3.1.2, 9.1.3.3.1, 9.1.3.3.2)</u>
System piping is arranged so that failure of any pipeline cannot inadvertently drain the Spent Fuel Pool (SFP) below the water level required for radiation shielding. This level is maintained by pool suction piping located 20 feet above the top of the fuel assemblies, and a siphon breaker on the cooling pipe's return line into the pool. This design ensures greater than ten feet of water exists over the top of the fuel assemblies should inadvertent drainage occur. Normal SFP water levels are maintained a minimum of 23 feet over the top of irradiated fuel assemblies seated in the storage racks.

The most serious failure of this system would be complete loss of water in the storage pool. To protect against this possibility, the SFP cooling suction connection enters near the normal water level so that the pool cannot be gravity-drained. The cooling water return line contains an antisyphon hole to prevent the possibility of gravity draining the pool.

If a failure should occur that would prevent the use of the SFP heat exchanger for cooling the SFP water (e.g., severance of the piping which constitutes the cooling recirculation path), natural surface cooling would maintain the water temperature at or below the boiling point. A Design Class I backup makeup water source is provided to ensure that the water level in the SFP can be maintained.

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Fuel and Heavy Load Handling Accidents (9.1.2.3, 9.1.4.3)
Limitations on fuel handling area crane travel preclude the possibility of dropping heavy objects from above the spent fuel racks. The spent fuel bridge hoist and the moveable partition wall monorail are the only cranes capable of moving objects over the spent fuel racks. The rated capacity of the spent fuel bridge hoist is 2000 pounds. An object of this weight dropped on the racks will not affect the integrity of the racks. The rated capacity of the moveable partition wall monorail is 4000 pounds, however, physical restrictions (trolley stops) are provided to prevent movement of loads over the SFP. Crane operation in the fuel handling area is such that the spent fuel cask cannot traverse over the spent fuel storage racks in the SFP.

The fuel handling system (FHS) consists of equipment and structures utilized for handling new and spent fuel assemblies in a safe manner during refueling and fuel transfer and cask loading operations. Fuel handling devices have provisions to avoid dropping or jamming of fuel assemblies during transfer operations. Fuel lifting and handling devices are capable of supporting maximum loads under seismic conditions. The fuel handling equipment will not fail so as to cause damage to any fuel elements should the seismic event occur during a refueling operation. The fuel transfer system, where it penetrates the containment, has provisions to preserve the integrity of the containment pressure boundary. Cranes and hoists used to lift spent fuel assemblies have a limited maximum lift height so that the minimum required depth of water shielding is maintained.

The manipulator crane and fuel transfer system control circuit are designed with numerous safety features to help prevent and maintain function during postulated failures. Conformance with the requirements of Safety Guide Number 13 ensures safety under normal and postulated accident conditions. Electrical interlocks (i.e., limit switches) are provided for minimizing the possibility of damage to the fuel during fuel handling operations. Mechanical stops are provided as the primary means of preventing fuel handling accidents.

Loss of Compressed Air System (9.3.1.3)
Loss of the normal air supply from the compressed air system will result in a safe shutdown of the unit. Most pneumatically operated devices in the plant that have safety-related functions are designed to maintain a safe position or to assume a safe position upon loss of air pressure. Movement to this safe position (or maintaining this safe position) is accomplished by means of spring-return actuators and compressed gas from the backup air/nitrogen supply system. All such pneumatically operated devices are designed to achieve this safe position in the required time under the most limiting conditions, including gradual loss of the normal air supply from the compressed air system. If an air operated valve is required to operate after an assumed loss of the compressed air system, then that valve is also provided with_a backup supply of compressed gas from the backup air/nitrogen supply system.

Loss of Ventilation/ Habitability of the Control Room (9.4.1, 9.4.1.2)
The control room HVAC system functions during all design accident conditions. The system permits continuous occupancy of control rooms under normal and design accident conditions. The system consists of three air conditioning units, air cooled condensing units, and

interconnecting refrigeration piping. The air conditioning units are staged by associated room thermostats.

The control room HVAC System has four modes of operation. They are as follows:

Mode 1: Conditioned air is supplied and returned through ducts to the designated service area of each unit. Approximately 27 percent of the return air is normally exhausted to the atmosphere and 73 percent of the return air is normally recirculated. The recirculated air is mixed with 27 percent outdoor makeup air and filtered through roughing filters, cooled (or heated), and supplied to the control room.

Mode 2: In the event of a fire in the control room, provisions are made for once through, 100 percent outdoor air operation. This mode exhausts the smoke from the room, thereby making it habitable. Roughing filters are used for filtering the outdoor air. The mode is manually initiated.

Mode 3: In the event of airborne toxic gas outside the control room, provisions are made for manual zone isolation, 100 percent recirculated air with 27 percent passing through the high-efficiency particulate air (HEPA) filters and charcoal banks. Human detection (odor/smell) is used to initiate this mode.

Mode 4: A mode of operation has been provided for use in the event of airborne radioactivity and the requirement of long-term occupancy of the control room. This mode isolates and pressurizes the control room and mechanical equipment room through the HEPA and charcoal filters with air from a low activity region to reduce local infiltration. The Mode 3 recirculation train operates concurrently. In the event an accident occurs in one unit, the system automatically selects the pressurization intake train of the opposite unit. With radiation detected at both pressurization intakes, one of the trains will start. However, the operator manually switches to the intake with lowest contamination. There are four manual selector switches on each unit: two mode selector switches

<u>Fire within the Plant (9.5.1)</u>
A Fire Protection Program for DCPP Units 1 and 2 has been established by PG&E. The program outlines the fire protection policy for the protection of structures, systems, and components important to safety as well as the procedures, equipment, and personnel required to implement the program. Appendix 9.5B of the DCPP FSAR provides an evaluation of the effects of postulated fires within the plant, to ensure the integrity if the reactor coolant system boundary, enable the plant to be placed in safe condition, and minimize the release of radioactivity.

<u>Failure of Main Condenser (10.4.1, 10.4.1.3)</u>
The main condenser provides a heat sink and collection volume for steam and condensate discharged from the main turbine, feedwater pump turbines, turbine bypass system, feedwater heater drains, and other miscellaneous flows, drains, and vents. The condenser will condense up to 40 percent of the full load main steam flow during a load rejection, startup, or shutdown. The steam generator relief protects the NSSS from overpressure if the condenser is not available or if the steam flow exceeds the capacity of the condenser. The

secondary system is normally not radioactive. However, in the event of primary-to-secondary leakage through leaking steam generator tubes, it is possible for the main steam to become radioactively contaminated. A discussion of the assumed leakage rates, treatment methods, and calculated activity levels is included in DCPP FSAR Section 11.1.6.

Flooding from the Circulating Water System (10.4.5.4)
A flooding analysis was performed based on the failure of an operator to properly secure a condenser waterbox manway cover. In order to obtain a conservative flooding rate for this scenario, waterbox manhole cover failure was assumed to be coincident with an operating error in which both circulating water pumps were running and both discharge gates were closed to the stops. In this event, approximately 43,000 gpm or 5,700 cfm of water could be expected to flow from a lower inlet waterbox manhole (the manholes with the greatest incident head of water). This flow would fill the sump and equipment pit storage areas below elevation 85 feet in 15 minutes, if the building drains are assumed to be functioning, and in 10 minutes, if the drains are not functioning. During this time, alarms would be given for turbine building sump high level and for water in the condenser pit. It may be assumed that the condensate pumps, being flooded, would have tripped, giving dramatic indication of an irregular condition. In order to provide additional time for operators to react to this flooding casualty, a fire door was installed between the main condensers and the corridor to the emergency diesel generator rooms in order to minimize the amount of water that could enter the compartments. The door is locked closed and monitored through the security system. This door will allow at least 12 more minutes (assuming no flow of water from the building) for the postulated manhole failure flow after sumps and pits are flooded, during which corrective action (tripping the circulating water pump involved or opening doors to the outside of the building, or both) may be taken before availability of the emergency generators could be jeopardized.

Subsequent to the fire door installation, a float switch system was mounted on the walls of the condenser pit. This instrumentation system eliminated the need for operator action in order to protect safety-related equipment from any type of circulating water system leakage. The system will automatically trip the circulating water pumps if water fills the condenser pit thereby assuring that the turbine building can not be flooded by a circulating water system leak. The system employs two out of three logic for a high degree of reliability and it provides a high condenser pit level alarm indication in the control room.

Rupture of Condensate and Feedwater Chemical Injection Tanks (10.4.9)
The condensate and feedwater injection systems are designed to provide adequate amounts of conditioning chemicals to the secondary system as required for the prevention of corrosion in the condensate and feedwater systems and the steam generators. The condensate and feedwater injection system has no safety function. Postulated ruptures or toppling of associated chemical storage tanks have been analyzed and found to present a minimal risk of adverse interaction with engineered safety features components located in the area.

The ethanolamine/hydrazine supply tanks are located in the turbine building such that no engineered safety features components are in the area that would be affected by a ruptured supply tank. The bulk ethanolamine storage tank is a vertical tank located in the turbine building. The postulated toppling of the tank is not expected to damage the nearby safety-related diesel fuel oil lines which are located within a covered, recessed trench. Spilled liquid would be confined within the trench and be prevented from reaching the diesel generator room by firestops. The chemical storage tanks associated with the auxiliary feedwater portion of the system are located in the auxiliary building such that motor-driven Auxiliary Feedwater Pump 1-3 could be put out of service by water entering its drip-proof enclosure. In the event of the failure of the drip-proof enclosure to protect Auxiliary Feedwater Pump 1-3 and the subsequent loss of Auxiliary Feedwater Pump 1-3, the other motor-driven auxiliary feedwater pump and the steam-driven auxiliary feedwater pump would remain available. A postulated rupture of the boric acid mix and feed tanks located in the turbine building would cause only a negligible depth of water to accumulate on the floor. The only engineered safety feature in the area is the diesel generator fire protection controls for Unit 1 only. These controls are wall-mounted above the floor and enclosed in a splash-proof box. Thus the conclusion of minimal risk of adverse interaction with engineered safety features components is supported.

4.0 REFERENCES

4.1 Diablo Canyon Power Plant Final Safety Analysis Report (FSAR), Revision 17, November, 2006
4.2 Diablo Canyon Power Plant Q-List, Rev. 25
4.3 CF3.ID19, Rev. 3, Classification of Structures, Systems and Components
4.4 MA1.ID17, Rev. ~~17~~ 21 Maintenance Rule Monitoring program
4.5 DCM T-14, Seismically Induced Systems Interactions, Rev. 3B
4.6 DIABLO CANYON POWER PLANT, UNIT NOS. 1 AND 2 - ISSUANCE OF AMENDMENTS 163 & 165 RE: CONTROL ROOM, AUXILIARY BUILDING, AND FUEL HANDLING BUILDING VENTILATION SYSTEMS, Feb. 27, 2004

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Diablo Canyon License Renewal Feasibility Study

TR-9DC

Plant Systems and Aging Management Programs

Topical Report

Revision 3

May 27, 2010

Plant Systems and Aging Management Programs
Diablo Canyon Power Plant

Approval Page

Revision	Prepared by:	Reviewed by:	Approved by:	Owner Acceptance:
0	Lynette Fang	Eric Blocher	Eric Blocher	-
Date	February 20, 2007	September 17, 2007	October 19, 2007	-
1	Gary Warner	Dave Kunsemiller	Eric Blocher	-
Date	March 31, 2008	April 01, 2008	April 04. 2008	-
2	Stan Shepherd	Rye Davis Ryan Gibbs	David Kunsemiller	-
Date	April 3, 2009	February 3, 2010	February 4, 2010	-
3	Russell Brownsberger	Dave Lipinski Al Saunders Jim Johnson Gary Warner	David Kunsemiller	Philippe Soenen
Date	May 25, 2010	May 26, 2010	May 26, 2010	May 27, 2010

Revision Summary

Revision	Required Changes to Achieve Revision	Date
0	Initial Issue	October 19, 2007
1	Revised HVAC system group assignments for Containment HVAC (23A3), Fuel Handling Bldg. (23D), and Radwaste Storage Facilties. Based on a review of the equipment list, added the following systems: Sanitary Sewage System (79), Laundry Facility/ Decontamination Equipment (82), Power Block Doors and Elevators (80), Steam Turbine Recorders & RVLIS Aux. Relays (47), Spare I&C Electrical Components (55), Building 110 CO Analyzers (58), PIMS equipment (90), Multiple System Panels (96), and Site Emergency and Containment Evacuation System (97). Revised scope (see notes) of Intake Structure and Intake Control Bldg (ZI) and Earthwork/Yard Structures (ZQ). Incorporated editorial changes.	April 04, 2008
2	Incorporated PCTF #14 which changed some structure names in Table 2.5 and added a note. Incorporated PCTF #23 which changed the name of LRID ZK in Table 2.5.	January 29, 2010

	Incorporated PCTF #30 which changed System 97 from out of scope to in scope in Table 2.6. Incorporated PCTF #32 which changed the Containment HVAC LRID and also changed the associated 1801 chapter in Table 2.2, and changed the 1801 chapter for LRID 23F in Table 2.3. Incorporated PCTF #33 which changed System 78 from out of scope to in scope, added VII as 1801 chapter and added Note 5, in Table 2.3. Incorporated PCTF #54 which made the following changes: 1. Changed System 72 from in scope to out of scope in Table 2.6. 2. Changed System 48 from out of scope to in scope in Table 2.6. 3. For Systems 53 and 54 in Table 2.6, changed MR, LRID and In-Scope to N/A and added Note 21 for System 53 and Note 22 for System 54. Updated in-scope and out of scope systems based on final revisions of Scoping reports and the LRA as submitted. Revised Cathodic Protection (Sys 72) to out of scope and changed name of system 52 to Emergency Response Facility Data Systems per final scoping packages.	
3	Incorporated PCTF-DC143 which added system 05 to scope. Extraction Steam and Heater Drip piping was found to have spatial interactions in the turbine building (reference Table 2.4). Incorporated PCTF-DC137 which added systems 27 and 79 to scope in Table 2.3, piping found to have spatial interactions in turbine building safety related rooms. Incorporated PCTF-DC135 which added note 27 and removed the administration building, as a separate structure, from Miscellaneous Structures and added it to the Turbine Building Table 2.5 Added note 28 to describe why systems 05, 27 and 79 are now in scope.	May 25, 2010

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1.0 PURPOSE OF TECHNICAL REPORT

This technical report identifies and lists the Diablo Canyon Power Plant (DCPP) systems and aging management programs that require license renewal review.

1.1 DCPP Systems Lists (Section 2.0)

A license renewal identifier (LRID) has been assigned to each system consistent with the plant system identifier noted in the DCPP Maintenance Rule Basis Document, Appendix A.

In section 2.1.3.1 of NUREG-1800 Standard Review Plan for License Renewal, the NRC has indicated its acceptance of the current industry practice of "realigning" or combining similar components from various systems. For example, containment isolation valves from various systems may be identified as a single system for purposes of license renewal. Systems and structures that were grouped together for license renewal review have been identified in the following list with a "Note" and assigned a group LRID. Numbered notes and LRIDs in the note column can be used to identify systems or structures that have been grouped together. To facilitate aging evaluations, the Reactor Pressure Vessel and Internals were assigned a unique LRID of RCVI. Consistent with the spaces approach, electrical and I&C components were grouped together and assigned a unique LRID of ELEC.

Each table in section 2 contains the following columns:

- Plant – DCPP equipment list system identification number
- MR –DCPP Maintenance Scoping document system or structure identifier
- LRID – License Renewal system or structure identifier
- In-Scope – Yes or No to identify system in-scope of license renewal. To facilitate schedule development at the start of the project, this column is approximated based on prior license renewal projects. Before the LRA is submitted to the NRC this column is updated to reflect actual scoping results
- System Name – System name identified in the DCPP FSAR, Plant Equipment List (PIMS), Maintenance Rule Basis Document or system name for special license renewal groups.
- MR Scope – Yes or no to identify system in the scope of the DCPP Maintenance Rule
- 1801 Ch – NUREG-1801 Chapter/Section most likely to be used for aging evaluations
- Note – Used to identify notes listed at the end of the section 2.

1.2 DCPP Aging Management Programs (Section 3.0)

Chapter XI of NUREG-1801 identifies the aging management programs (AMPs) and associated program elements that are relied upon in approving generic program applicability in NUREG-1801 Chapters two through eight. AMPs to be credited for DCPP aging management were selected from the aging management programs listed in Chapter XI of NUREG-1801 and are identified with a "Yes" or "No" in the AMP Exceptions column. NUREG-1801 Chapter XI AMPs not credited for aging management at DCPP are identified with an N/A in the AMP Exception column.

All AMPs identified as potential DCPP aging management programs were assessed to determine exceptions to NUREG-1801 requirements. This assessment was performed to allow initial assignment of standard notes during the aging evaluation phase of the project and before completion of the aging management program 10 element evaluations. AMPs with at least one exception to a NUREG-1801 program element are identified with a "YES" in the AMP exception column. All AMPs credited for aging management at DCPP receive an aging management 10 element evaluation. Upon completion of the 10 element evaluations the aging evaluation standard notes and these tables will be revised consistent with the AMP exceptions identified.

Each table in section 3 contains the following columns:

- NUREG 1801 Ref. – Identifies AMP section in NUREG-1801 Chapter XI
- NUREG-1801 Aging Management Program – Name of AMP for reference section of NUREG-1801 Chapter XI
- AMP Exception – Yes if at least one AMP exception is identified. N/A if AMP is not credited for aging management at DCPP.
- Note – Used to identify assessment considerations. Notes are listed at the end of the section 3

2.0 DCPP SYSTEMS LIST

2.1 Reactor Coolant Systems
GALL Chapter IV SRP Section 3.1

PLANT	MR	LRID	In-Scope	System Name	MR Scope	1801 Ch	Note
07	7A	07	Yes	Reactor Coolant System Includes: RVLIS & RVRLIS (7B)	Yes	IV.C2 IV.B2	
07	7B						
07	7A	PZR	Yes	Pressurizer		IV.C2	1
07	7A	SGR	Yes	Steam Generator		IV.D1	1
07	7B	RXC	Yes	Reactor Core Includes: - Nuclear Fuel (95) - Control Rod Mechanical SSCs (41A)			1
95	95						
07	7B	RCVI	Yes	Reactor Vessel and Internals		IV.A2& IV.B2	1

2.2 Engineering Safety Systems (ESF)
GALL Chapter V SRP Section 3.2

Plant	MR	LRID	In Scope	System Name	MR Scope	1801 Ch	Note
09	09	09	Yes	Safety Injection	Yes	V.D1	
10	10	10	Yes	Residual Heat Removal	Yes	V.D1	
12	12	12	Yes	Containment Spray	Yes	V.A	
23	23A1	23A	Yes	Containment HVAC Includes: - Containment H2 Control (23A1/A2) - Containment HVAC (23A3)	Yes	V.C & VII.F3	
23	23A2						
23	23A3						
45	45B		Yes	Containment Isolation Valves	Yes		2

2.3 Auxiliary Systems
GALL Chapter VII SRP Section 3.3

PLANT	MR	LRID	In-Scope	System Name	MR Scope	1801 Ch	Note
08	8A	08	Yes	Chemical and Volume Control System	Yes	VII.E1	3
08	8B						
11	11A	11	Yes	Nuclear Steam Supply Sample System	Yes	VII.C2	3
11	11B						
13	13A	13	Yes	Spent Fuel Pool Cooling System Includes: - Spent Fuel Pool Cooling (13A) - Spent Fuel Pool Purification (13B)	Yes	VII. A3	
13	13B						
14	14	14	Yes	Component Cooling Water System	Yes	VII.C2	
15	15	15	Yes	Service Cooling Water	Yes	VII.C2	
16	16A	16	Yes	Makeup Water System Includes - Domestic & Drinking Water (part of 16B)	Yes	VII.C2	3
16	16B						
17	17A	17	Yes	Saltwater and Chlorination System Includes: - Saltwater System (17A) - Auxiliary Saltwater System (17B) - Chlorination (17C)	Yes	VII.C1	
17	17B						
17	17C						
18	18A	18	Yes	Fire Protection System Includes: - Fire Detection System (18A) - Firewater System (18B) - CO2 System (18C) - Halon (Sim/Comp Rooms) sys. (18E) - Portable Fire Extinguishers (18F)	Yes	VII.G	
18	18B						
18	18C						
18	18E						
18	18F						
19	19	19	Yes	Liquid Radwaste System	No	VII	5
20	20A	20	Yes	Lube Oil System	Yes	VII	3
20	20B						
21	21A	21	Yes	Diesel Generator System	Yes	VII.H2	
21	21B	21B	Yes	Diesel Generator Fuel Transfer System	Yes	VII.H1	4
23	23B	23B	Yes	Auxiliary Building HVAC Includes: - Main Aux Building HVAC (23B) - Misc. Aux Bldg. HVAC (23C1 & C2) - Fuel Handling Building (23D)	Yes	VII.F2	3, 4
23	23C1 & C2						
23	23D						

PLANT	MR	LRID	In-Scope	System Name	MR Scope	1801 Ch	Note
23	23F1 & F2	23F	Yes	Control Room HVAC Includes: - Control Room HVAC (23F1 & F2) - Plant Process Computer HVAC (23F3)	Yes	VII.F1	4
23	23F3						
23	23E1	23	Yes	Miscellaneous HVAC Systems Includes: - Turbine Building (23E1 & E2) - ASW Pump Room Vent. (23G1 & G2) - Radwaste Storage Bldg. HVAC	Yes	VII.F3 VII.F4	3
23	23E2						
23	23G1						
23	23G2						
24	24	24	Yes	Gaseous Radwaste System	Yes	VII	
25	25A	25	Yes	Compressed Air System Includes: - Compressed Air System (25A) - Backup Air and N2 System (25B) - Compressed Breathing Air (25C)	Yes	VII.D	
25	25B						
25	25C						
26	26	26	No	Nitrogen and Hydrogen System	Yes	VII.D	5
27	27	27	Yes	Oily Water and Turbine Sump System	No	VII.C VII.G	28
28	28	28	Yes	Secondary Sample System	No	VIII	5
39	39	39M	Yes	Radiation Monitoring (Mechanical)	Yes		24
42	42A	42	Yes	Cranes and Fuel Handling Includes: - Fuel Handling System (42A) - Cranes, Hoists & Monorails (42B) - Nuclear Fuel Storage (42C)	Yes	VII.A2 VII.B	
42	42B						
42	42C						
75	75		No	Emergency Eyewash & Shower Stations	Yes	VII	25
79	79	79	Yes	Sanitary Sewage System	Yes	VII.C VII.G	28
18	18D		No	Halon (SSPS Rooms) System	No		6
77	77	77	No	Hazardous Waste System	No		
78	78	78	Yes	Solid Radwaste Handling System	No	VII	5
82	82	82	No	Laundry Facility/Decontamination Equipment	No		

2.4 Steam and Power Conversion Systems GALL Chapter VIII SRP Section 3.4

PLANT	MR	LRID	In-Scope	System Name	MR Scope	1801 Ch	Note
02	2A	02	Yes	Condensate Includes: - Condensate (2A) - Condensate Polishing (2B)	Yes	VIII.E	
02	2B						
03	3A	03	Yes	Feedwater	Yes	VIII.D1 VIII.G	3
03	3C						
03	3B	3B	Yes	Auxiliary Feedwater Includes: - Auxiliary Feedwater (3B) - Long Term Cooling Water -Aux Feedwater Alt. Suction Sources (3D)	Yes	VIII.G	4
03	3D						
04	4A	04	Yes	Turbine Steam Supply (TSS) System Includes: - TSS –Downstream of MSIV (4A) - TSS –Upstream of MSIV (4B) - TSS –Steam Generator Blowdown (4C)	Yes	VIII.A VIII D1	7
04	4B						
04	4C						
05	5	05	Yes	Extraction Steam & Heater Drip	Yes	VIII.C	28
06	6	06	Yes	Auxiliary Steam System	Yes	VIII.B1	
22	22	22	No	Turbine Generator Associated Systems	Yes		

2.5 Structures
GALL Chapter II SRP Section 3.5

LRID	In-Scope	Structure Name	MR Scope	1801 Ch	Note
ZA	Yes	Auxiliary Building	Yes	III.A3	
ZC	Yes	Containment	Yes	II.A1/3 III.A1/4/5	
ZE	Yes	230-kV Switchyard, 500kV Switchyard, and Electrical Foundations/Structures	Yes	III.A3	8
ZF	Yes	Fuel Handling Building	Yes	III.A5	
ZI	Yes	Intake Structure and Intake Control Building	Yes	III.A6	
ZJ	Yes	Control Room (Located in Auxiliary Building)	Yes	III.A1	
ZK	Yes	Diesel Fuel Oil Transfer Pump Vaults and Structures	Yes	III.A3	
ZM	Yes	Pipeway Structure	Yes	III.A3	
ZQ	Yes	Earthwork/Yard Structures	Yes	III.A6	10, 11
ZR	Yes	Radwaste Storage Facilities	Yes	III.A3	10, 21
ZSUP	Yes	Supports	Yes	III.B	
ZT	Yes	Turbine Building	Yes	III.A3	27
ZW	Yes	Outdoor Water Storage Tank Foundations and Encasements	Yes	III.A8	10, 12
ZX	Yes	Discharge Structure	No	III.A6	
N/A	N/A	Power Block Doors and Elevators (System 80)	No	III. A	9
N/A	N/A	Fire Rated Assemblies and Barriers (System 98)	Yes	VII. G	13
ZY	No	Independent Spent Fuel Storage Installation (ISFSI) & Cask Transfer Facility (CTF)	No		
ZZ	No	Miscellaneous Structures	No		
	No	Fire Water Pump House (located in Patton Flats)	No		
	No	Auxiliary boiler enclosure	No		14
	No	Avila gate guardhouse	No		14
	No	Avila gate storage building	No		14
	No	Bechtel administration trailers	No		14
	No	Bio-lab shower / Laboratory facility	No		14
	No	Biological laboratory and offices	No		14
	No	Blast and paint facility	No		14
	No	Boat dock	No		14
	No	Boat repair shop	No		14
	No	Building, auto, and land services trailer	No		14

LRID	In-Scope	Structure Name	MR Scope	1801 Ch	Note
	No	Building mechanic shop	No		14
	No	Chemical storage building	No		14
	No	Chlorination and domestic water building (not in use)	No		14
	No	Clarifier and make-up pretreatment building	No		14
	No	Document Control RMS Building	No		14
	No	Document storage facilities	No		14
	No	Emergency Operations Facility	No		14
	No	Employee assistance program office trailer	No		14
	No	Energy Information Center	No		14
	No	Engineering services trailer	No		14
	No	Environmental monitoring program facilities	No		14
	No	Firing range	No		14
	No	Fitness for duty buildings	No		14
	No	Fitness trailer	No		14
	No	Fleet mechanic office	No		14
	No	Gas cylinder storage	No		14
	No	General construction paint compressor building (not in use)	No		14
	No	General construction paint shack / sand blast facility	No		14
	No	Hazardous waste facility	No		14
	No	Hazardous material office and warehouse	No		14
	No	Housekeeping field office	No		14
	No	Intake maintenance shop	No		14
	No	Intake office/security access building	No		14
	No	Ionics reverse osmosis facility	No		14
	No	Laundry facility	No		14
	No	Learning center and maintenance shop	No		14
	No	Learning center and simulator	No		14
	No	Main warehouse	No		14
	No	MATCON express trailer	No		14
	No	Meteorological Tower No. 1 and building	No		14
	No	Meteorological Tower No. 2 and building	No		14
	No	NOS project files	No		14
	No	Nuclear Quality Services trailer	No		14

LRID	In-Scope	Structure Name	MR Scope	1801 Ch	Note
	No	Oceanography laboratory	No		14
	No	Offsite emergency laboratory	No		14
	No	Old Steam Generator Storage Facility	No		14
	No	Outage services facilities	No		14
	No	Plant compressed air facility	No		14
	No	Plant security building and structures	No		14
	No	Portable fire pump building	No		14
	No	Raw water collection facility and wells at Diablo Creek	No		14
	No	Radiation protection trailer	No		14
	No	Restroom trailers	No		14
	No	Scaffold storage building	No		14
	No	Security guard station	No		14
	No	Service air pad building	No		14
	No	Sewage treatment plant	No		14
	No	Site overlook	No		14
	No	Storage building - 500 kV switchyard	No		14
	No	Technical maintenance/Telecom/Medical facility	No		14
	No	Telecommunications trailer	No		14
	No	Telephone terminal building	No		14
	No	Turbine generator equipment warehouse	No		14
	No	Unit 2 cold machine shop	No		14
	No	Utility Crew / Firewatch / Radwaste field office	No		14
	No	Vehicle maintenance shop	No		14
	No	Vehicle maintenance shop parts office	No		14
	No	Vending machine facility	No		14
	No	Warehouse A	No		14
	No	Warehouse B	No		14
	No	Wastewater holding and treatment equipment enclosure	No		14
	No	Westinghouse office trailer	No		14
	No	Yard Containment Access Facility	No		14

2.6 Electrical and Instrumentation & Controls NUREG-1800 Chapter VI & NUREG-1801 Section 3.6

PLANT	MR	LRID	In-Scope	System Name	MR Scope	1801 Ch	Note
35	35	35	Yes	AMSAC	Yes	VI.A	
36	36	36	Yes	Eagle 21	Yes	VI.A	
37	37	37	Yes	Nuclear Instrumentation System	Yes	VI.A	
38	38	38	Yes	Solid State Protection System	Yes	VI.A	
39	39A	39	Yes	Radiation Monitoring	Yes	VI.A	3
39	39B						
41	41B	41	Yes	Control Rod Electrical SSCs	Yes	VI.A	
48	48	48	Yes	Incore Flux Mapping	No		
51	51A	51	Yes	Seismic Monitoring System Includes: - Reactor Seismic Trip (51A) - Seismic Monitoring (51B)	Yes	VI.A	
51	51B						
52	52	52	Yes	Emergency Response Facility Data System	Yes	VI.A	26
60	60	60	Yes	Communications	Yes	VI.A	
61	61	61	Yes	Main Gen. Electrical Equipment (25kV)	Yes		
62	62	62	Yes	12 kV System	Yes	VI.A	
63	63A	63	Yes	4 KV System	Yes	VI.A	3
63	63B						
64	64A	64	Yes	480V System	Yes	VI.A	3
64	64B						
65	65A	65	Yes	120V AC System	Yes	VI.A	3
65	65B						
67	67A	67	Yes	125V DC System	Yes	VI.A	3
67	67B						
68	68C	68	Yes	Emergency Lighting Includes: - Emergency AC Lighting (68C) - Emergency DC Lighting (68D) - Battery Operated Lighting (68E) - Control Room Lighting (68F) - Pipe Rack Lighting (68G)	Yes	VI.A	
68	68D						
68	68E						
68	68F						
68	68G						
69	69	69	Yes	230 KV System	Yes	VI.A	8
70	70	70	Yes	500 KV System	Yes	VI.A	8

PLANT	MR	LRID	In-Scope	System Name	MR Scope	1801 Ch	Note
97	97	97	Yes	Site Emergency and Containment Evacuation System	No		
33	33	33	No	Plant Data Network	No		
34	34	34	No	Aux Bldg Control Board Digital System (ABCBDS)	No		
40	40	40	No	Meteorological Monitoring	No		
43	43A	43	No	Plant Process Computer & Annunciator System	Yes		
43	43B						
44	44	44	No	Security	No		
46	46	46	No	Loose Parts Monitoring	No		
47	N/A	N/A	N/A	Steam Turbine Recorders & RVLIS Auxiliary Relays	No		16
50	50	50	No	Digital Rod Position Indication	Yes		
53	N/A	N/A	N/A	Nuclear Monitoring System	No		22
54	N/A	N/A	N/A	CCTV Monitoring System	No		23
55	N/A	N/A	N/A	Spare I&C & Electrical Components	No		17
58	N/A	N/A	N/A	Building 110 CO Analyzers	No		18
66	66	66	No	Security UPS	No		
68	68A	XE01	No	120V General Use & Normal Lighting	No		
68	68B						
71	71	71	No	Boric Acid Heat Trace System	No		
72	72	72	No	Cathodic Protection System	Yes	VI.A	15
90	90	N/A	N/A	PIMS Equipment	No		19
96	96	N/A	N/A	Multiple System Panels	No		20

Notes for DCPP System Tables:

1. The following Reactor Coolant System Components are evaluated separately for license renewal:
   - Pressurized (LRID PZR)
   - Steam Generators (LRID SGR)
   - Reactor Vessel and Internals (RCVI)
   - Reactor Core (RXC) – Includes Nuclear Fuel (95) and control Rod Mechanical SSCs (41)
2. CIVs are evaluated with their process system and not as a separate CIV group.
3. Includes MR and Non-MR portions of the system or safety and non-safety portions of the system.
4. The MR system ID is used as LRID for License Renewal Feasibility Study.
5. Potentially in the scope of license renewal for criterion (a)(2).
6. The Halon system for the SSPS rooms is no longer installed at DCPP – all components have been removed.
7. The Steam Generators are evaluated in LRID SGR.
8. Includes structures relied upon to demonstrate compliance with 10 CFR 50.63 (SBO). This also includes electrical ductbanks and manways.
9. The plant equipment list assigns Power Block doors and elevators to system 80. Power Block doors and elevators are evaluated with their applicable structure. No LRID is assigned for system 80.
10. Structure relied upon to demonstrate compliance with 10 CFR 50.48 (Fire Protection).
11. Earthwork/Yard Structures includes:
    - Earth slopes (slope east of Auxiliary Building & Slope over ASW line east of Intake)
    - Intake Revetment (rip rap at Intake Cove)
    - East and West Breakwater
    - Circulating Water Conduits
    - Auxiliary Saltwater (ASW) conduits
    - ASW Vacuum Breaker Vaults
    - Raw Water Reservoir number 1A and 1B
12. Outdoor Water Storage Tank Foundations includes the following tanks:
    - Refueling Water Storage Tanks (Concrete encased steel tank)
    - Condensate Storage Tank (concrete encased steel tank)
    - Primary Water Storage Tank (steel tank)
    - Fire Water Tank (steel tank)
13. The plant equipment list assigns Fire Rated Assemblies and Barriers to System 98. Fire Rated Assemblies and Barriers are evaluated with their applicable structure. No LRID is assigned for system 98.
14. Included in Miscellaneous Structures. The list of out of scope structures was updated in Table 2.5 to reflect the final list of structures identified in the LRID ZZ Scoping Report.

15. Although it is recognized that the loss of function for the Cathodic Protection System will not render safety related SSCs incapable of performing their intended functions, a conservative maintenance rule determination for maintenance rule scoping is made. There is no CLB requirement for Cathodic Protection System.
16. System 47 contains Steam Turbine recorders and RVLIS auxiliary relays. Steam Turbine recorders are evaluated in System 04 (Turbine Steam Supply) with other recorders assigned to the Turbine Steam Supply System. RVLIS auxiliary relays are evaluated in System 07 (Reactor Coolant System)with the other RVLIS components. No LRID is assigned for system 47.
17. System 55 contains spare electrical breakers, motors, valve operators, and I&C components that are rotated in and out of service in various plant electrical distribution and I&C systems. No LRID is assigned for system 55.
18. System 58 contains CO analyzers located in Building 110 paint/blast booths and a 125 VDC circuit breakers for the calibrations room. The 125 VDC breaker has been assigned to and will be evaluated with LRID 67 – 125V DC system. The CO analyzers are maintenance equipment. No LRID is assigned for system 58.
19. System 90 does not contain any components installed in plant systems. This system contains a workstation and an Uninterruptable Power Supply for the PIMS Computers. No LRID is assigned for system 90.
20. System 96 contains Vertical Boards 1VB1 thru 1VB5 (similar for Unit 2) that are seismically qualified panels and contain components that are put together in a logical order to aid in the operation of the plant. The individual components are not system 96, they belong to other systems. All panel numbers refer to the structural enclosure that is evaluated in LRID ZSUP. No LRID is assigned for system 96.
21. The Radwaste Facilities include the Solid Radwaste Storage Facility (SRSF) and the Radwaste Storage Building.
22. System 53 contains no components. DCPP determined that this is not a valid system ID.
23. System 54 contains no components. This system is used to track portable CCTV equipment used for maintenance.
24. System LRID 39M comprises the mechanical portions of the Radiation Monitoring System.
25. System 75 Emergency Eyewash and Shower Stations contains no components. The water supply is domestic water and is evaluated in system LRID16.
26. System 52 (LRID 52) name in the DCPP FSAR is Emergency Response Facility Data System which includes among other subsystems the Safety Parameter Display System. In the Maintenance Rule Basis Document the system 52 name is Safety Parameter Display System. For the purposes of the Integrated Plant Assessment the FSAR name was adopted. The LRA however uses Safety Parameter Display System.
27. The Turbine Building includes the Emergency Diesel Generator Rooms, CCW Heat Exchanger Room, and the Administration Building and associated walkway.

28. Systems 05, 27 and 79 were found to be in the scope of license renewal after plant walkdowns discovered system components in safety related rooms (Emergency Diesel Generator Rooms and CCW Heat Exchanger Room) of the Turbine Generator building. Systems 05 and 79 are in scope for (a)(2) only. System 27 is in scope for (a)(2) and (a)(3).

3.0 DCPP AGING MANAGEMENT PROGRAMS

3.1 Mechanical AMPs

NUREG-1801 REF.	NUREG-1801 AGING MANAGEMENT PROGRAMS MECHANICAL	AMP Exception	Notes
XI.M1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	No	1
XI.M2	Water Chemistry	Yes	
XI.M3	Reactor Head Closure Studs	Yes	1
XI.M4	BWR Vessel ID Attachment Welds	N/A	3
XI.M5	BWR Feedwater Nozzle	N/A	3
XI.M6	BWR Control Rod Drive Return Line Nozzle	N/A	3
XI.M7	BWR Stress Corrosion Cracking	N/A	3
XI.M8	BWR Penetrations	N/A	3
XI.M9	BWR Vessel Internals	N/A	3
XI.M10	Boric Acid Corrosion	No	
XI.M11A	Nickel-Alloy Nozzles & Penetrations	No	
XI.M12	Thermal Aging Embrittlement of CASS	No	4
XI.M13	Thermal Aging & Neutron Embrittlement of CASS	No	4
XI.M14	Loose Part Monitoring	N/A	5
XI.M15	Neutron Noise Monitoring	N/A	5
XI.M16	PWR Vessel Internals	N/A	6
XI.M17	Flow-Accelerated Corrosion	Yes	7
XI.M18	Bolting Integrity	Yes	8
XI.M19	Steam Generator Tube Integrity	No	9
XI.M20	Open-Cycle Cooling Water System	No	
XI.M21	Closed-Cycle Cooling Water System	Yes	10
XI.M22	Boraflex Monitoring	N/A	11
XI.M23	Inspection of Overhead Heavy Load and Light Load(Related to Refueling) Handling Systems	No	
XI.M24	Compressed Air Monitoring	N/A	12
XI.M25	BWR Reactor Water Cleanup System	N/A	
XI.M26	Fire Protection (Fire Barriers & Diesel Fire Pump)	Yes	13
XI.M27	Fire Water System	Yes	14
XI.M28	Buried Piping and Tanks Surveillance	N/A	15
XI.M29	Aboveground Carbon Steel Tanks	N/A	16

NUREG-1801 REF.	NUREG-1801 AGING MANAGEMENT PROGRAMS MECHANICAL	AMP Exception	Notes
XI.M30	Fuel Oil Chemistry	Yes	17
XI.M31	Reactor Vessel Surveillance	No	18
XI.M32	One-Time Inspection	No	
XI.M33	Selective Leaching of Materials	Yes	19
XI.M34	Buried Piping and Tanks Inspection	Yes	15
XI.M35	One-Time Inspection Of ASME Code Class 1 Small-Bore Piping	Yes	1
XI.M36	External Surfaces Monitoring Program	Yes	
XI.M37	Flux Thimble Tube Inspection	No	
XI.M38	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Yes	
XI.M39	Lubricating Oil Analysis	Yes	
PSNI	Plant Specific Nickel Alloy	No	

3.2 Structural AMPs

NUREG-1801 REF.	NUREG-1801 AGING MANAGEMENT PROGRAMS STRUCTURAL	AMP Exception	Notes
XI.S1	ASME Section XI, Subsection IWE (Steel containment/liners)	Yes	20
XI.S2	ASME Section XI, Subsection IWL (concrete containment)	No	20
XI.S3	ASME Section XI, Subsection IWF (supports)	No	1
XI.S4	10 CFR Part 50, Appendix J	No	
XI.S5	Masonry Wall Program	No	21
XI.S6	Structures Monitoring Program	No	21,22
XI.S7	RG 1.127, Water-Control Structures Inspection	No	22
XI.S8	Protective Coatings	N/A	23

3.3 Electrical AMPs

NUREG-1801 REF.	NUREG-1801 AGING MANAGEMENT PROGRAMS ELECTRICAL	AMP Exception	Notes
XI.E1	Electrical Cables and Connections – Not 50.49 Environmental qualification Requirements	No	
XI.E2	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	No	24
XI.E3	Inaccessible Medium Voltage Cables – Not 50.49	No	25
XI.E4	Metal-Enclosed Bus	No	26
XI.E5	Fuse holders	No	27
XI.E6	Electrical Cable Connections – Not 50.49	Yes	
N/A	Plant Specific Transmission Conductor, Connections and Switchyard Bus and Connections.	Yes	28

Notes:

1. NUREG – 1801 references 2001 edition thru 2002 & 2003 addenda of the (ASME) Boiler and Pressure Vessel (B&PV) Code, Section XI. DCPP is currently undergoing the third ISI interval, which is scheduled to end according to the following schedule:
   Unit 1 – 5/7/2015
   Unit 2 – 3/13/2016
   The applicable edition of the Code to be used has not been determined but DCPP will adhere to the most current addenda available.
2. Deleted.
3. Applicable to BWRs only.
4. There is cast austenitic stainless steel (CASS) in the primary loop piping. For pump casings and valve bodies, based on the assessment documented in the letter dated May 19, 2000 from NRC to NEI, screening for susceptibility to thermal aging is not required.
5. Aging Management Reviews do not typically identify the need for this AMP.
6. For reactor internals aging management, DCPP documents participation in industry programs for investigating and managing aging effects on reactor internals. AMP XI.M16 was deleted in NUREG-1801 Rev. 1. Guidance for aging management of PWR Vessel Internals is provided in the AMR line items of NUREG-1801 Chapter IV, as appropriate.
7. NUREG-1801 XI.M17 specifies following the guidance of NSAC-202L-R2. The DCPP Flow Accelerated Corrosion Program implements the guidelines provided in the EPRI Guideline NSAC-202L-R3.
8. NUREG 1801 AMP XI.M18 specifies the use of ASME Section XI 1995 edition with Addenda 1996. The ISI program is required to comply with the latest edition and addenda of the Code incorporated by reference in 10 CFR 50.55a one year prior to the start of an inspection interval. DCPP applies the ASME B&PV Code consistent with the ISI AMP (NUREG-1801 XI.M1). Loss of preload is not a parameter of inspection for DCPP bolting integrity program. Inspection interval is not necessarily daily as suggested in NUREG-1801, XI.M18 for pressure boundary bolting connections reported to be leaking.

9. The Steam Generators will be replaced during 2R14 and 1R15 which are scheduled for Feb 2008 and Jan 2009.
10. The EPRI Closed Cooling Water Chemistry Guideline, Revision 1, establishes a normal chromate concentration operating range of 150 – 300 ppm, while DCPP operates in the chromate concentration range of 1580 – 3150 ppm. The EPRI Closed Cooling Water Chemistry Guideline, Revision 1, establishes chloride and fluoride as control parameters to be monitored monthly, however DCPP does not monitor these control parameters in the diesel engine cooling water (DECW) system. The EPRI Closed Cooling Water Chemistry Guideline, Revision 1, establishes a monthly monitoring frequency for diesel engine cooling water (DECW) control parameters under stable conditions. DCPP performs quarterly monitoring of the DECW control parameters under stable conditions.
11. DCPP was issued a License Amendment on Sept. 5, 2007 to take credit for soluble boron in the spent fuel criticality analysis. DCPP takes no credit for the Spent Fule Rack Boraflex Neutron Absorber in Region 1 of the Spent Fuel Pool Criticality Analysis
12. Plant specific programs/practices are typically determined during Aging Management Reviews. Compressed gas SSCs within the scope of license renewal are expected to be minimal and to contain a dry gas environment that does not result in aging effects that require aging management. Depending on plant specific materials and operating experience, no aging management, or as a minimum, use of M38 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting may be required.
13. NUREG-1801 XI.M26 specifies a visual inspection of fire barrier walls, ceilings, and floors on an 18-month basis, but DCPP performs the inspections every 24 months to coincide with the 24 month refueling cycles. NUREG-1801 XI.M26 stipulates a six month frequency for CO2 system tests and inspections, but DCPP performs them on an 18 month frequency.
14. NUREG-1801 XI.M27 stipulates that periodic flow testing of the fire water system is performed using the guidelines of NFPA-25, but DCPP performs this test every three years in accordance with the NFPA Fire Protection Handbook. NUREG-1801 XI.M27 specifies annual hydrant hose hydrostatic tests. DCPP performs a hydrostatic test of its power block fire hoses every three years.
15. Buried Piping and Tanks Inspection in NUREG-1801 M28 is based on coatings and cathodic protection. NUREG-1801 XI.M34 Buried Piping and Tank Inspection AMP is based on opportunistic inspections and is assumed to be credited. NUREG-1801 XI M34 typically requires further evaluation of the detection of aging effects and operating experience. Based on DCPP operating experience a Buried Piping and Tank Inspection AMP (NUREG-1801 XI.M34) will be required.
16. The above ground outdoor tanks at DCPP will be managed by the Structures Monitoring Program NUREG-1801 XI.S6.
17. DCPP uses only ASTM Standard D 1796-83, not D1796 and D2709. DCPP's Technical Specification is committed to using only D1796-83.
18. Reactor Vessel Surveillance is evaluated as part of the TLAA Review
19. A qualitative determination of selective leaching will be used in lieu of the Brinell hardness testing identified in NUREG-1801 XI.M33.
20. NUREG – 1801 references 2001 edition thru 2002 & 2003 addenda of the (ASME) Boiler and Pressure Vessel (B&PV) Code, Section XI. DCPP CISI program performs inspections in accordance with ASME Section XI Subsection IWE &IWL 1992 edition with the 1992 addenda.
21. Masonry Wall Program is integrated with the Structures Monitoring Program.
22. DCPPis not committed to Regulatory Guide 1.127. Water Control Structures will be evaluated as a separate aging management activity integrated with the scope of the Structures Monitoring Program.
23. Aging management reviews are expected not to require use of the coatings AMP. If required, service Level 1 coatings used at STARS facilities are assumed to be in accordance with RG 1.54.

24. Aging Management of Instrumentation circuits is assumed to be limited to radiation monitoring and neutron detector cables.
25. Inaccessible medium-voltage cables exposed to moisture that are installed in duct banks will require aging management review and crediting of a new aging management activity based on XI.E3.
26. DCPP uses metal enclosed bus between the ESF Transformers and the ESF switchgear
27. DCPP has an Approved Fuse List that lists all fuses used at DCPP. AMR review is expected to identify fuses at DCPP that are not located within active equipment or identify fuses that are routinely removed from fuse blocks. Some fuses that are pulled are assumed to use removable fuse holders that are designed to be pulled without removal of the fuse from the fuse clip. Therefore, fuse holders will require crediting a new aging management program.
28. Plant specific Transmission Conductor AMP added to scope by WIN-15DC based on evaluation of Switchyard and transmission design and PG&E operating experience.

Diablo Canyon License Renewal Feasibility Study

TR-7DC

Electrical/I&C Plant Spaces Approach

License Renewal Feasibility Study Position Paper

Revision 1

January 21, 2010

Electrical/I&C Plant Spaces License Renewal Feasibility Study Position Paper
Diablo Canyon Generating Station

Approval Page

Revision	Prepared by:	Checked By:	Approved by:
0	Gary Warner	George Kyle	Eric Blocher
Date	February 11, 2009	February 11, 2009	February 13, 2009
1 Date	Kurt Lathrop January 14, 2010	George Kyle January 14, 2010	Dave Kunsemiller January 21, 2010

Revision Summary

Revision	Required Changes to Achieve Revision	Date
0	Initial Issue	February 13, 2009
1	Add discussion of mechanical components in electrical systems per TR-PCTF-085	

TABLE OF CONTENTS

1.0 PURPOSE OF POSITION PAPER

The License Renewal Rule, 10 CFR 54.4 (Ref 1), requires that the structures, systems, and components (SSC) relied on in safety analyses or plant evolutions to perform a function that demonstrates compliance with the Commission's regulations be identified.

This position paper identifies the methodology used in the scoping and screening of the Diablo Canyon Electrical and I&C systems and components. The results of the aging evaluation review for the passive electrical components within the scope of license renewal are documented in position paper TR-11DC, "Electrical Component Aging Evaluation."

2.0 ELECTRICAL and I&C SYSTEM SCOPING

System scoping is performed for each electrical and I&C system at Diablo Canyon in accordance with the general guidance for system and structure scoping provided in Project Instruction PI-1 (Ref 4). The scoping results have the same content and appearance as those for mechanical systems. The system functions are described. Functions and support systems are identified for in-scope systems. The results of electrical and I&C system scoping are used to support evaluations of generic passive electrical and I&C components during application of the spaces approach.

Information from the system level scoping for in-scope systems supports the License Renewal Application (LRA). Guidance concerning system scoping is found in the NRC Standard Review Plan (SRP) for the Review of License Renewal Applications for Nuclear Power Plants" (Ref 2).

2.1 Electrical and I&C System Scoping Methodology

A list of electrical and I&C systems is developed and the systems are scoped against the criteria of 10 CFR 54.4(a). The list of electrical and I&C systems and the results of the scoping are provided in LRA Table 2.2-1, Plant-Level Scoping Results.

System Level Scoping

At the system level, the scoping methodology utilized for electrical and I&C systems is similar to the mechanical system-level scoping. The FSAR descriptions, maintenance rule database records, current licensing basis documents and design basis documents applicable to the system are reviewed to determine the system safety classification and to identify all of the system functions. All system level functions are evaluated against the criteria of 10 CFR 54.4(a)(1), (a)(2) and (a)(3). The supporting systems needed to maintain the in-scope system intended functions are identified and evaluated against the criteria in 10 CFR 54.4(a)(2).

Electrical Boundary Drawings

Unlike mechanical systems, individual license renewal drawings were not created for each electrical and I&C system. Electrical license renewal drawings are created. The plant One Line Diagram schematically shows the portions of the plant AC electrical distribution system, including the Station Blackout recovery path, that are included in the scope of license renewal. The plant DC Main Single Line schematically shows the portions of the plant DC electrical distribution system that are included in the scope of license renewal.

Component Level Scoping

All electrical and I&C components that perform an intended function as described in 10 CFR 54.4 for in-scope systems are included in the scope of license renewal.

The controlled plant component database does not list electrical component types such as cables, connections, fuse holders, terminal blocks, high-voltage transmission conductors, connections and insulators, switchyard bus and connections. During scoping the installed electrical components are identified by reviewing documents such as plant drawings and databases. Additionally industry documents, such as NEI 95-10 provide a list of typical electrical components found in nuclear power plants. These lists are reviewed against engineering information for the plant to determine which electrical component types are installed at DCPP. The electrical component types installed at DCPP but not listed in the plant component database are added into the license renewal database for evaluation during component screening.

3.0 SPACES APPROACH FOR AGING MANAGEMENT REVIEW

In the spaces approach, the aging management review is based on areas where bounding environmental conditions are identified. An example of a bounding environmental parameter is the highest average temperature present in the defined space. This aging condition is applied to all generic Non Environmentally Qualified (EQ) component types, which might be found within the bounding spaces. For components covered by the station EQ program, the applicable conditions and areas of application are provided in the EQ Binders, which are TLAAs that are reconciled for the extended duration in accordance with the provisions of 10 CFR 54.

The following process is used to perform an aging management review of a single component type for a specific environmental stressor:

- Screen and identify passive component types.
- Identify the passive component type's materials of construction.
- Determine the value of the bounding environmental parameter to which the component type is exposed.
- Identify aging effects for the component type when exposed to the environmental stressor.

- Compare the aging characteristics of the identified materials to the bounding environment and determination if the component type is able to maintain their intended function during the period of extended operation (i.e. perform on license renewal intended function).

This process is applied for each component type, regardless of the License Renewal system the subject component type belongs to. Specific system assignment to component types is only needed to resolve exceptions, which result from the spaces approach analyses.

Under the spaces approach all electrical and I & C components are assumed to be within the scope of license renewal rule unless the components are clearly in systems which are not in the License Renewal scope, or which are determined by other means to be outside license renewal scope.

Only in-scope passive electrical and I&C components represented as component types require aging management analysis.

4.0 ELECTRICAL and I&C COMPONENT SCREENING

The use of the spaces approach to aging management eliminates the need for specifically associating electrical and I&C components with license renewal systems. Active electrical and I&C components do not require aging management review. Passive components are conservatively assumed to be within the scope of License Renewal. This approach is recognized in NRC Standard Review Plan (SRP) for the Review of License Renewal Applications for Nuclear Power Plants" (Ref 2). SRP Section 2.5.1 "Areas of Review":

> For an electrical and I&C system that are within the scope of license renewal, an applicant would not identify the specific electrical and I&C components that are subject to an aging management review. For example, an applicant may not "tag" each specific length of cable that is "passive," "long-lived," and performs an intended function as defined in 10 CFR 54.4(b). Instead, an applicant would use the so-called "plant spaces" approach (Ref. 1) which is explained below. The "plant spaces" approach provides efficiencies in aging management review of electrical equipment located within the same plant space environment.

Later in the section, licensee flexibility is specifically noted:

> 10 CFR 54.21(a)(1)(i) provides many examples of electrical and I&C components that are not considered to be "passive" and are not subject to an aging management review for license renewal. Therefore, an applicant is expected to identify only a few electrical and I&C components, such as electrical penetrations, cables, and connections, that are "passive" and subject to an aging management review.
>
> An applicant has the flexibility to determine the set of electrical and I&C components for which an aging management review is performed, provided that this set

encompasses the electrical and I&C components for which the Commission has determined an aging management review is required.

Based on the above the following process is used to screen electrical and I&C components using the License Renewal Data Management Tool in accordance with PI-1 (Ref 4).

- The "component type" field of electrical and I&C components in the license renewal database is used to identify electrical and I&C components. Types, identified as electrical and I&C components, are listed in Table 5-1, along with the determination of whether they are active or passive in accordance with the guidance in NEI 95-10, Revision 4 (Ref 3).

- All components having these component types are assigned to License Renewal System Number ELEC, "Electrical Components".

- Initially, every electrical & I&C component is conservatively identified as being within the scope of License Renewal (The field titled "LR Scope" is checked).

- For each component, the check box field titled "Passive" is initially unchecked. If the component type is identified as passive in NEI 95-10 Appendix 1 (Ref 3) this check box is checked.

- For each component where the field titled "Passive" is checked, the appropriate component passive intended function code from PI-1, Attachment H, "Passive Structure and Component Intended Functions", is entered into the field titled "Func 1". If the component has more than one passive intended function, each of the passive intended functions are entered.

- For each component listed as passive, the field "Long Lived" is checked by default. If the component is not long lived, uncheck the field titled "Long Lived" and provide the plant procedure that is used to periodically change the component out. PI-1, Attachment G contains a list of short-lived components that do not require an aging management review.

- For each in-scope passive component provide an external environment and material.

- Electrical and I & C components, which are clearly in systems which are not in the License Renewal scope, or which are determined by other means to be outside license renewal scope, may have the field titled "LR Scope" unchecked.

- Generic component types are added for the electrical and I&C components that are not normally assigned plant component Ids. Table 5-2 provides a list of the generic electrical and I&C components to be added based on the plant's documentation.

4.1 Electrical and I&C System Component Screening Methodology

The screening of electrical and I&C components uses the spaces approach which is consistent with the guidance in NEI 95-10. The spaces approach to aging management review is based on areas where bounding environmental conditions are identified. The bounding environmental conditions are applied during aging management review to evaluate the aging effects on electrical component types that are located within the bounding area. Use of the spaces approach for aging management review of electrical components types eliminates the need to associate electrical and I&C components with specific systems that are within the scope of license renewal. The in-scope electrical components are categorized as "active" or "passive" based on the determinations documented in NEI 95-10, Appendix B. The passive long-lived electrical and I&C components that perform an intended function without moving parts or without change in configuration or properties are grouped into component types such as cables, connections, fuse holders, terminal blocks, high-voltage transmission conductors, connections and insulators, switchyard bus and connections. Component-level intended function(s) are determined for each in-scope passive electrical component type and recorded in the license renewal database. The passive in-scope electrical component types are identified in the license renewal database as subject to an aging management review. A list of the passive in-scope electrical component types subject to aging management is provided in LRA Table 2.5-1, "Electrical Component Types Subject to Aging Management Review."

4.2 Mechanical Equipment in Electrical Systems

After all active component types have been assigned to the ELEC License Renewal System, as described above, there may be component types that are non-electrical in nature in a plant system and no License Renewal Identification (LRID) number will have been assigned. These components may be determined to be one of three types:

- The component type may be in error, the component is actually active. The error is corrected and the component is added to the ELEC License Renewal System.

- The component may be a mechanical component that is actually a sub-component of an active electrical component. The plant system designation is added to the list of License Renewal Systems and the component is assigned to that License Renewal System as an active component. The comment field will describe which electrical component contains this mechanical sub-component.

- The component may represent a mechanical portion of an electrical system (e.g., valves, piping, and pumps for a sampling system that are represented on a P&ID). If the system performs no license renewal intended function, a note is entered in the Comments field describing the fact that mechanical components are included in the system. If electrical scoping determines the system performs a license renewal intended function, then the plant system is broken into both a mechanical and an electrical system (e.g., Radiation Monitoring may become both an Electrical and a Mechanical License Renewal System). The electrical components will be evaluated as described above. The mechanical components will be evaluated as described in PI-1 (Ref. 4).

5.0 TABLES

5.1 TABLE 5-1 DIABLO CANYON ELECTRICAL and I&C COMPONENT TYPES

Component Type	Passive	Comment
Annunciator	No	
Anode	No	
Battery	No	
Breaker	No	
Cabinet	No	
Camera	No	
Charger Battery	No	
Comparator	No	
Computer	No	
Computer Hardware	No	
Connector	Yes	
Controller	No	
Converter	No	
Detector	No	
Electrical Equip	No	The enclosure is passive and is added as a Generic Structures Component
Electrical Panels & Enclosures	No	The enclosure is passive and is added as a Generic Structures Component
Electrode	No	
EPT Terminator	No	
Fuse	No	
Generator	No	
Ground	Yes	Only within the scope of license renewal when the grounding system performs an intended function
Heater	No	
I/O Board	No	
Indicator	No	
Instrument	No	
Inverter	No	
Isolator	No	
Lighting Light	No	
Load Center	No	
Meter	No	
Microwaves	No	
Modifier	No	

Component Type	Passive	Comment
Module	No	
Monitor	No	
Motor	No	
Multiplexer	No	
Panel Board	No	The enclosure is passive and is added as a Generic Structures Component
Power Supply	No	
Recorder	No	
Regulator	No	
Relay	No	
Repeater	No	
Resistor	No	
RTD	No	
Sensor Element	No	
Solenoid Valve	No	
Starter	No	
Switch	No	
Switchyard Bus and Connections	Yes	
Terminal Block	Yes	
Terminal Box	No	The enclosure is passive and is added as a Generic Structures Component
Termination	Yes	See generic component added for connections
Timer	No	
Transducer	No	
Transformer	No	
Transmission Conductors and Connections	Yes	
Transmitter	No	
Variable Speed Drive	No	
Voltage Divider	No	

5.2 TABLE 5-2 GENERIC ELECTRICAL AND I &C COMPONENTS

Component Type	Passive	Comments
Cable Connections (Metallic Parts)	Yes	
Cable Tray and Supports	Yes	Add as a Generic Structures Component
Insulated Cable and Connections	Yes	
Conduits and Supports	Yes	Add as a Generic Structures Component
Electrical Panels and Enclosures	Yes	Add as a Generic Structures Component
Electrical Splices	Yes	Part of the Generic component for Insulated Cable and Connections
Fuse Holder Metallic Clamp	Yes	When not part of a larger assembly
High Voltage Insulators	Yes	
Metal Enclosed Bus	Yes	
Penetrations Electrical	Yes	Non-EQ penetrations
Switchyard Bus and Connections	Yes	
Terminal/Fuse Blocks Insulation Parts	Yes	Not part of a larger assembly
Transmission Conductors and Connections	Yes	
Tie Wraps	Yes	When required to support the CLB or are credited in the plant's seismic qualification calculations for raceway supports

6.0 REFERENCES

1. 10 CFR Part 54 "Requirements for Renewal of Operating Licenses for Nuclear Power Plants"
2. NUREG-1800 Rev 1 "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants"
3. NEI 95-10 Rev 6 "Industry Guideline for Implementing the Requirements of 10 CFR Part 54-License Renewal Rule"
4. PI-1 "Scoping and Screening of Systems, Structures and Components for STARS License Renewal Projects"

Diablo Canyon License Renewal Feasibility Study

TR-2DC

Station Blackout (SBO)
License Renewal Feasibility Study Position Paper

Revision 2~~1~~

~~February 15, 2008~~~~April 3, 2009~~January 29, 2010

SBO License Renewal Feasibility Study Position Paper
Diablo Canyon Power Plant

Approval Page

Revision	Prepared by:	Reviewed by:	Approved by:
0	David Boortz	Rudy Ortega Gary D. Warner	Eric A. Blocher
Date	February 2, 2007	August 31, 2007	September 01, 2007
1	Greg Whittier Jim Johnson	Al Saunders Dave Kunsemiller	Eric Blocher
Date	February 15, 2008	February 15, 2008	February 15, 2008
2	Stan Shepherd	Gary Warner	David Kunsemiller
Date	April 3, 2009	June 17, 2009	January 29, 2010

Open Items:

1. None

Revision Summary

Revision	Required Changes to Achieve Revision	Date
0	Initial Issue.	9/01/2007
1	Revised section 3.1 through section 3.5 and Table 3.1/3.2 to use TR-9DC system designators/names and structure designators/names. Added Intake Structure and Control Building (ZI) and Earthwork/Yard Structures (ZQ) to Section 3.3 and Table 3-2. In Section 3.1 and Table 3-1 added Makeup Water System (16) for the Condensate Storage Tank and deleted Condensate System (02).	2/15/2008
2	Incorporated PCTF #05 which added the Feedwater System (System 03) to the list of systems required for reactor decay heat removal (provides flow path for AFW)	4/3/2009

	in Section 3.1 and Table 3-1, and added Reference 19. Incorporated PCTF #08 which added the Control Room (LRID ZJ) to the list of structures in Table 3-2 and in Section 3.3. Incorporated PCTF #18 which corrected the Structure Function description for LRID ZW and revised the associated reference in Table 3-2. Incorporated PCTF #24 which clarified that System 23 consists of four separate LRIDs in Table 3-1. Incorporated PCTF #38 which added LRID ZK in Section 3.3 and Table 3-2. Incorporated PCTF #43 which a Note at the bottom of Table 3-2. Made editorial changes to References and Table 3-1	

TABLE OF CONTENTS

1.0 PURPOSE OF POSITION PAPER

The License Renewal Rule, 10 CFR 54.4(a)(3), requires that the structures, systems, and components (SSCs) relied on in safety analyses or plant evolutions to perform a function that demonstrates compliance with the Nuclear Regulatory Commission’s (NRC) regulations for station blackout 10 CFR 50.63 be identified.

This position paper identifies the Diablo Canyon Power Plant (DCPP) systems and structures relied upon to demonstrate compliance with 10 CFR 50.63 (Loss of All Alternating Current Power). This document is for the use of license renewal project personnel engaged in the preparation, review, or approval of scoping and screening evaluations in support of license renewal feasibility activities for DCPP.

2.0 SBO CURRENT LICENSING BASIS (CLB) REQUIREMENTS FOR DCPP

Station Blackout (SBO) at DCPP is defined as loss of the 500-kV and 230-kV switchyards with the failure of two emergency diesel generators (EDGs) to operate in one of the units. The other unit is assumed to experience only loss of offsite power (Reference 10 Section 8.3.1.6).

2.1 SBO REGULATORY REQUIREMENTS

<u>SBO Rule Requirements</u>
The SBO rule (10 CFR 50.63) requires that nuclear power plants have the capability to withstand and recover from the loss of offsite and onsite AC power of a specified duration (the coping duration). Regulatory Guide (RG) 1.155 (Reference 2) and NUMARC 87-00 (Reference 3) provide guidance on selecting the time period for which a licensee must cope with the SBO. Station Blackout is not applicable to loss of available AC power to buses fed by station batteries via inverters nor is it applicable to loss of AC power from an SBO defined alternative AC power source (Reference 2, Part B).

<u>NUREG-1800, Revision 1: Scoping of SBO Equipment for License Renewal</u>
NUREG-1800, Sections 2.1.3.1.3 and 2.5.2.1.1 (Reference 6) indicate that a license renewal applicant’s scoping methodology includes systems, structures and components (SSCs) relied upon during the “coping duration” and “recovery” phase of an SBO event. Because the SBO rule (Reference 1) and RG 1.155 (Reference 2) include procedures to recover from an SBO that include offsite and onsite power, the plant system portion of the offsite power system that is used to connect the plant to the offsite power source should also be included within the scope of the rule. This path typically includes switchyard circuit breakers that connect to the offsite system power transformers (startup transformers), the transformers themselves, the intervening overhead or underground circuits between circuit breaker and transformer and onsite electrical distribution system, and the associated control circuits and structures.

2.2 DCPP STATION BLACKOUT CLB

The NRC issued a supplemental safety evaluation report (SSER) on May 29, 1992. This SSER concluded that DCPP's revised response to the Station Blackout Rule (10 CFR 50.63) for Units 1 and 2 to be acceptable (Reference 11)

The DCPP SBO analysis was performed using the guidance provided in NUMARC 87-00, Rev. 0 and the coping time (the postulated maximum SBO duration) was determined to be 4 hours (Reference 10 Section 8.3.1.6). During an SBO event, the SBO analysis demonstrated that the plant could be safely shutdown utilizing either Buses G or H and their normally connected EDGs (Emergency AC (EAC) sources) and, thereby, the third EDG and its Bus F were declared the Alternate AC (AAC) source. However, during an SBO event, any of the three EDGs may be used as the AAC source. The SBO analysis takes credit for the hydraulic interconnection of the ASW systems between Unit 1 and 2 by manually opening FCV-601. DCPP has committed to the "10 minute AAC" option, therefore a "coping assessment" is not required (Reference 10 Section 8.3.1.6). Furthermore this means that NUMARC 87-00 Sections 7.2.1 through 7.2.5 and Section 2.5 are not applicable for assessment or submittal. (References: 1, 2 Section 3.2.5, and 3 Section 7.1.2)

3.0 SYSTEMS AND STRUCTURES REQUIRED TO COMPLY WITH SBO

Equipment needed to cope with and recover from an SBO is identified in the revised response to the SBO rule for DCPP (Reference 4). Systems and structures that are necessary for compliance with SBO rule are presented in the following sections:

- Section 3.1- SBO Coping Systems
- Section 3.2- SBO Recovery Systems
- Section 3.3- Structures

3.1 SBO COPING SYSTEMS

The coping time (the postulated maximum SBO duration) was determined to be 4 hours (Reference 10). While coping with an SBO, the equipment necessary for SBO coping is not assumed to be susceptible to a single failure or required for a design basis accident. The systems necessary for SBO coping provide the following functions:

- Reactor Decay Heat Removal
- Containment Isolation
- Reactor Coolant Inventory Control
- Support for SSC Credited During Coping

Reactor Decay Heat Removal

Decay heat is removed from the core by natural circulation of the reactor coolant. This heat is then transferred to the secondary side of the SGs, and discharged to the atmosphere through the atmospheric steam dump valves (ADVs). A nitrogen accumulator is provided for each of the ADVs. Makeup feedwater to the SGs is provided from the condensate storage tank either by a motor-driven AFW pump (if Bus H is available), or by the turbine-driven AFW pump (if Bus H is not available). Systems providing a Reactor Decay Heat Removal function during the 4 hour coping time include:

- Makeup Water System (Includes Condensate Storage Tanks)(16)
- Auxiliary Feedwater (03B)
- Main Feedwater (03)
- Turbine Steam Supply System (04)
- Reactor Coolant (07)
- Component Cooling Water (14)

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Containment Isolation

NUMARC 87-00, Section 7.2.5 defines “containment integrity” as the capability for valve position indication and closure of containment isolation valves independent of the preferred Class 1E power supplies. The containment isolation valves requiring this capability are valves that may be in the open position at the onset of an SBO. Acceptable means of position indication include local mechanical indication, DC-powered indication, and AAC-powered indication. RG 1.155, Part C.3.2.7, allows containment isolation valves that meet the following criteria to be excluded from the SBO functionality requirements:

- Valves normally locked closed during operation
- Valves that fail closed on a loss of power
- Check valves
- Valves in non-radioactive closed-loop systems not expected to be breached during an SBO
- Valves less than three inches in nominal diameter

Regulatory Guide 1.155 lists five classifications of valves which are exempt from consideration when evaluating containment isolation capability for station blackout. There are sixteen at valves at DCPP that do not meet any of the exclusion criteria. Of these, fourteen are designated as SA and are required to function for proper alignment of the emergency core cooling and other safety systems. The only two valves not excluded from consideration for SBO are ES designated valves 8100 and 8112 associated with Penetration 45. These are motor-operated valves (MOVs). MOV 8100 is outside of containment, and MOV 8112 is inside containment. EP ECA-0.0, “Loss of All AC Power," contains specific direction to the operators to close MOV 8100 locally in the event of an SBO, and MOV 8100 is capable of being closed by means of a local handwheel (Reference 15). Therefore, no systems will be included in scope for SBO Containment Isolation.

Reactor Coolant Inventory Control
Even with the Reactor Coolant Pumps (RCPs) not in operation, the RCP seals need to be protected from overheating by the reactor coolant. The thermal barriers, cooled by component cooling water (CCW), are capable of preventing overheating and degradation of the RCP seals. Since a CCW pump is supplied by the F Bus, CCW cooling of the RCP seals will be available. In addition, since a centrifugal charging pump is also powered by Bus F, RCP seal injection is essentially uninterrupted. Either CCW cooling of the thermal barriers or seal injection alone is capable of maintaining adequate RCP seal cooling which secures the integrity of the RCP seal. Since shutdown to cold conditions is not required during the 4-hour coping period, no loss of RCS volume due to water shrinkage during cooldown needs be addressed (Reference 4 Section C). Systems providing Reactor Coolant Inventory Control function during the 4 hour coping time include:

- Reactor Coolant (07)
- Component Cooling Water (14)
- Saltwater and Chlorination (Includes Aux. Saltwater)(17)

Support for SSC Credited During Coping
Electrical power is required to support systems that provide coping functions. An Electrical Power support function for SSCs credited during coping is provided by:

Electrical Systems
- 4 kV (63)
- 480 V (64)
- 120 V AC (65)

Auxiliary Systems
- Diesel Generator (21)
- Diesel Generator Fuel Transfer (21B)
- HVAC System (23)
  See LRID breakdown in Table 3-1
- 125 V DC (67)

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3.2 SBO RECOVERY SYSTEMS

Recovery from an SBO focuses on restoration of an AC power source. This can either be from the onsite diesel generators, or from an offsite source. The primary offsite power recovery path is from the 230 kV switchyard through the standby startup transformers, which energize the 12 kV Buss. Offsite power can be restored from the 500 kV switchyard by opening the motor-operated disconnect for the main generator, supplying power through the main transformer to the unit auxiliary transformer. This is illustrated on the Electrical Distribution System overview drawing (Reference 9) and documented in procedure EP EGA-0.3 Restore Vital Buss (Reference 7). Systems providing an SBO Recovery function include:

- 12 kV (62)
- Main Generator Electrical Equipment (25 kV) (61)
- 4 kV (63)
- 230 kV (69)
- 500 kV (70)

3.3 STRUCTURES

Plant structures provide physical support and protection for systems or components that either penetrate the structure wall or are supported by the structure wall, floor, and roof. Direct interface is through the system or component supports that are anchored to the structure. The DCPP plant structures that provide physical support and protection for systems that are credited for complying with the SBO Rule are the following:

- Auxiliary Building (ZA)
- Containment Building (ZC)
- Intake Structure and Intake Control Building (ZI)
- Control Room (ZJ)
- Diesel Fuel Oil Pump Vaults and Structures (ZK)
- Earthwork/Yard Structures (Includes ASW Conduits and ASW Vacuum Breaker Vaults) (ZQ)
- Turbine Building (Includes Diesel Generator Building)(ZT)
- Outdoor Water Storage Tank Foundation Encasements (ZW)
- Concrete Pads for Station Transformers (ZE)
- 230 – kV Switchyard (Includes Circuit Breaker Structure) (ZE)
- 500 – kV Switchyard (Includes Circuit Breaker Structure) (ZE)

3.4 CASCADING OF SYSTEMS

First-level, primary support systems (or structures) that are necessary for the functioning of equipment credited to perform SBO Coping and Recovery evolutions or otherwise demonstrate compliance with 10 CFR 50.63 "Station Blackout" are included within the scope of 10 CFR 54. To comply with the License Renewal Rule, 10 CFR 54.4(a)(3), second-, third- and fourth-level support systems, back-up systems and systems or structures not

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explicitly credited in a current licensing basis (CLB) document to be available during this regulated event are not considered.

3.5 TABLE 3-1 AND TABLE 3-2

For the purpose of determining the systems and structures within the scope of license renewal per 10 CFR 54.4(a)(3), those systems that are required for an SBO are listed in Table 3-1, and the associated structures are shown in Table 3-2. Each table will include the following columns:

Table 3-1

- System – system designator identified in TR-9DC LRID column
- System Name – system name identified in TR-9DC
- System Function – license renewal system intended function for regulated event
- CLB Reference – reference number from Section 4 of Position Paper to be noted. As necessary a specific section of the reference may be identified.

Table 3-2

- Structure – structure designator identified in TR-9DC LRID column
- Structure Name – structure name identified in TR-9DC
- Structure Function – license renewal system intended function for regulated event
- CLB Reference – reference number from Section 4 of position paper to be noted. As necessary a specific section of the reference may be identified.

4.0 REFERENCES

1. 10 CFR 50.63, "Loss of All Alternating Current Power (Station Blackout)," July 21, 1988

2. Regulatory Guide (RG) 1.55, "Station Blackout," August 1988

3. Nuclear Management and Resources Council, Inc., (NUMARC) 87-00, Guideline and Technical Bases for NUMARC Initiative Addressing Station Blackout at Light Water Reactors, November 1987, Errata Sheet October 1988

4. DCL-92-084, "Diablo Canyon Units 1 and 2 Revised Response to Station Blackout" April 13, 1992

5. DCM T-42, Rev 9, Station Blackout Design Criteria Memorandum

6. NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," Revision 1, September 2005

7. DCPP FSAR Section 6.5.1.1, Rev 17, "Auxiliary Feedwater System, Design Conditions"

8. Plant Information Management System (PIMS)

9. Dwg No. 57483, General Outdoor Arrangement Drawing, 500 and 230 kV electrical systems.

10. DCPP FSAR 8.3.1.6 Rev 17, Station Blackout

11. NRC Letter 920529, "Supplemental Safety Evaluation of PG&E –Response to Station Blackout Rule 10 CFR 50.63"

12. DCPP FSAR Section 9.2.2.2, Rev 17, "Component Cooling Water System Description"

13. Diablo Canyon Power Plant Q-list

14. NRC Letter 920129, "Safety Evaluation of Diablo Canyon Station Blackout Analyses (TAC Nos. M68537 and M68538), enclosure to letter from H. Rood (U.S. NRC) to G. M. Rueger (PG&E), January 29, 1992. (ACTS No. 31572)

15. DCL-91-206, "Additional Information Regarding Station Blackout" April 15, 1991

16. FSAR Section 8.3.1.1.6, Rev 17, "120 Volt AC Instrument System"

17. FSAR Section 8.3.2.2, Rev 17, "Class IE 125 V DC System

18. FSAR Section 9.2.7.3, Rev. 17, “Safety Evaluations”

19. FSAR Section 10.4.7, Rev. 17, “Condensate and Feedwater Systems”

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TABLE 3-1
Systems Relied upon to Demonstrate Compliance with Station Blackout

System Id.	System Name	System Function	CLB Reference
03	Main Feedwater	Coping Reactor Decay Heat Removal Provide a flow path to the Steam Generators for Auxiliary Feedwater	References 7, 19
03B	Auxiliary Feedwater	Coping Reactor Decay Heat Removal Provide feedwater to the Steam Generators for decay heat removal using the Turbine Driven Auxiliary Feedwater Pump.	Reference 7, Section 6.5.1.1 Reference 4, Sections B and C
04	Turbine Steam Supply	Coping Reactor Decay Heat Removal Remove reactor decay heat using the atmospheric relief valves	Reference 4, Sections B and C
07	Reactor Coolant	Coping Reactor Decay Heat Removal Reject reactor decay heat using the Steam Generators. Coping Reactor Coolant Inventory Control Maintain reactor coolant pressure boundary to ensure inventory is maintained	Reference 4, Sections B and C
14	Component Cooling Water	Coping Reactor Coolant Inventory Control The Component Cooling Water System (CCWS) removes heat from the RCP seals and prevents overheating and degradation of the RCP seals.	Reference 4, Sections B and C Reference 12, Section 9.2.2.2
16	Make-up Water System	Coping Reactor Decay Removal Provide a source of makeup water via the CSTs to the Steam Generators through the Turbine Driven Auxiliary Feedwater Pump.	Reference 14 Ssection 2.2.1
17	Saltwater and Chlorination	Coping Reactor Coolant Inventory Control The Auxiliary Salt Water System (ASWS) supplies cooling water from the ultimate heat sink, the Pacific Ocean, to the component cooling water (CCW) heat exchangers.	Reference 4, Section B Reference 11
21	Diesel Generator	Coping Support for SSC The Emergency Diesel Generators (EDGs) provide onsite emergency AC power in the event of a loss of offsite power	Reference 4, Section C Reference 10, Section 8.3.1.6
21B	Diesel Generator Fuel Transfer	Coping Support for SSC Provides diesel fuel to the diesel generator for the alternative AC source	Reference 4, Section C

TABLE 3-1 (continued)
Systems Relied upon to Demonstrate Compliance with Station Blackout

System Id.	System Name	System Function	CLB Reference
23	HVAC System ~~LRID 23A: Containment Ventilation and H2 Control~~ LRID 23B: Auxiliary ~~P~~Bldg. Ventilation LRID 23F: Control Room Area Ventilation LRID 23: Misc. Ventilation (Includes Diesel & Intake Structure Ventilation)	Coping Support for SSC HVAC provides ventilation for equipment and habitability ~~No~~ Yes Yes Yes	Reference 4, Section B and Tables 2, 3 and 4 Reference 5, Section 2.3
61	Main Generator Electrical Equipment (25 kV)	Recovery Provides offsite recovery power via 500 kV switchyard	Reference 4, Section D
62	12 kV	Recovery The 12 kV system distributes power to the 4160V System	Reference 4, Section D
63	4 kV	Coping Support for SSC The 4160 volt electric power system provides 4160 volt power for the operation and control of Class 1E loads and non-Class 1E loads Recovery The 4160 volt electric power system provides 4160 volt power for the operation and control of Class 1E loads and non-Class 1E loads	Reference 4, Section D Reference 5, Section 2.3
64	480 V	Coping Support for SSC The 480V System for the operation and control of Class 1E loads and non-Class 1E loads	Reference 4, Section C Reference 5, Section 2.3

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65	120 V AC	Coping Support for SSC Vital - provides 120V power for the operation and control of Class 1E	Reference 16 Reference 5, Section 2.3
67	125 V DC	Coping Support for SSC The 125V DC provides a continuous source of direct current to AC inverters	Reference 17 Reference 5, Section 2.3
69	230 kV	Recovery Provides offsite power to the 12 kV system	Reference 4, Section D Reference 5, Section 2.3
70	500 kV	Recovery Provides offsite power to the 25 kV system	Reference 4, Section D Reference 5, Section 2.3

TABLE 3-2
Structures Relied upon to Demonstrate Compliance with Station Blackout

Struct. Id.	Structure Name	Structure Function	CLB Reference
ZA	Auxiliary Building	Physical Support and Protection The function of the auxiliary building is to provide protection for equipment used for coping with and recovery from an SBO.	Reference 4, Tables 2, 3 and 4
ZC	Containment	Physical Support and Protection The function of the containment building is to provide protection for equipment used for coping with and recovery from an SBO.	Reference 4, Tables 2, 3 and 4
ZE	230-kV Switchyard, 500kV Switchyards, and Electrical Foundations/Structures	Physical Support and Protection Provides support for the 230/500 kV power lines, physical foundations for the startup transformers, and the 230/500 kV control buildings provide protection for equipment used for coping with and recovering from an SBO	Reference 4, Section D
ZI	Intake Structure and Intake Control Building	Physical Support and Protection The function of the Intake Structure and Intake Control Building is to provide support and protection for the Aux. Saltwater equipment used for coping with and recovery from an SBO.	Reference 18
ZJ	Control Room (Located in Auxiliary Building)	Physical Support and Protection The Control Room provides protection for equipment used for coping with and recovery from an SBO.	Reference 4, Tables 2, 3 and 4
ZK	Diesel Fuel Oil Pump Vaults and Structures	Physical Support and Protection The function of the Diesel Fuel Oil Pump Vaults and Structures is to provide support and protection for EDG Fuel Oil system, which is required for coping with and recovery from an SBO.	Reference 4, Section C
ZQ	Earthwork/Yard Structures	Physical Support and Protection The function of the Earthwork/Yard Structures is to provide support and protection for the Aux. Saltwater (ASW) Conduits and ASW Vacuum Breaker Vaults used for coping with and recovery from an SBO.	Reference 18

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ZT	Turbine Building (Includes Emergency Diesel Generator Rooms)	Physical Support and Protection The function of the diesel generator building is to provide protection for equipment used for coping with and recovery from an SBO	Reference 4, Tables 2, 3 and 4
ZW	Outdoor Water Storage Tank Foundations and Encasements	Physical Support and Protection ~~The function of the outdoor water storage tank foundations and Encasements is to provide the foundation~~Provide physical support ~~-~~for the Condensate Storage Tank ~~that is~~ used for coping with and recovery from an SBO.	Reference 14, ~~Tables 2, 3 and 4~~Section 2.2.1

Note: Component supports that are required to demonstrate compliance with SBO regulations are addressed in LRID ZSUP.

Diablo Canyon License Renewal Feasibility Study

TR-1DC

Anticipated Transients Without Scram (ATWS)
License Renewal Feasibility Study Position Paper

Revision 2

January 21, 2010

ATWS License Renewal Feasibility Study Position Paper
Diablo Canyon Power Plant

Approval Page

Revision	Prepared by:	Reviewed by:	Approved by:
0	Lynnette Fang	Gary D. Warner	Eric A. Blocher
Date	February 22, 2007	August 7, 2007	August 7, 2007
1	David Kunsemiller	Gary D. Warner	Eric A. Blocher
Date	March 14, 2008	March 18, 2008	March 21, 2008
2	Stan Shepherd	Gary D. Warner	David F. Kunsemiller
Date	May 5, 2009	June 22, 2009	January 21, 2010

Open Items:

None

Revision Summary

Revision	Required Changes to Achieve Revision	Date
0	Initial Issue	August 7, 2007
1	Revised Section 3.2 through 3.5 and Table 3.1/3.2 to use TR-9DC system designators/names and structures designators/names. Editorial change to reference License Renewal Feasibility Study.	March 21, 2008

2	Incorporated PCTF #13 which added the Control Room (ZJ) System to Table 3-2 and Section 3.3. Incorporated PCTF #20 which added the Main Steam System (System 04) to Table 3-1. Incorporated PCTF #21 which changed Reference 12. Incorporated PCTF #64 which added a more detailed description of PT-505, -506, the transmitters that provide redundant first stage impulse pressure input from the HP turbine to the reactor trip circuit, and added associated references. Incorporated PCTF #70 which added the 125VDC System (System 67) to Section 3.2 and Table 3-1 because it is an ATWS mitigation support system. Reference 13 was also added by PCTF #70. Also, minor editorial changes were made to Section 4.0, References.	May 5, 2009

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1.0 PURPOSE OF POSITION PAPER

The License Renewal Rule, 10 CFR 54.4(a)(3), requires that the structures, systems, and components (SSC) relied on in safety analyses or plant evolutions to perform a function that demonstrates compliance with the Commission's regulations for anticipated transients without scram (10 CFR 50.62) be identified.

This position paper identifies the Diablo Canyon Power Plant and structures relied upon to demonstrate compliance with 10 CFR 50.62 (Requirements for reduction of risk from Anticipated Transients Without Scram (ATWS) events for light-water-cooled nuclear power plants). This document is for the use of License Renewal Feasibility Study personnel engaged in the preparation, review, or approval of scoping and screening evaluations in support of license renewal feasibility study activities for Diablo Canyon Power Plant (DCPP).

2.0 ATWS CURRENT LICENSING BASIS (CLB) REQUIREMENTS FOR DCPP

An ATWS is a postulated operational transient, which automatically initiates auxiliary feedwater, isolates Steam Generator blowdown and sample lines, and initiates a turbine trip independent of the reactor trip system. The probability of an ATWS event is very low and its occurrence requires multiple failures. This condition, turbine trip without reactor trip, has been evaluated by Westinghouse for plants equipped with full load rejection capability and has been found to be acceptable (Ref. 5).

2.1 ATWS REGULATORY REQUIREMENTS

ATWS Rule Requirements
On June 26, 1984, the NRC issued 10 CFR 50.62 (ATWS Rule) (Ref 1). The ATWS Rule required improvements in the design of commercial nuclear power facilities to reduce the probability of failure to shutdown the reactor following anticipated transients, and to mitigate the consequences of an ATWS event. Each pressurized water reactor must have equipment from sensor output to final actuation device, which is diverse from the reactor trip system, to automatically initiate the auxiliary feedwater system and initiate a turbine trip. The following equipment is required by the ATWS Rule for reduction of risk from an ATWS event at DCPP:

- The ATWS Mitigation System Actuation Circuitry (AMSAC) cabinet.
- The plant protection system supplies steam generator level and two main turbine first stage pressure inputs to AMSAC.
- The motor driven auxiliary feedwater control circuits supply signals to the Steam generator blowdown and sample line containment isolation valves.
- The main turbine trip and the main turbine backup trip circuits which trip the turbine.

2.2 DCPP ANTICIPATED TRANSIENTS WITHOUT SCRAM CLB

After years of study, the NRC concluded that the existing plant protection systems were sufficiently reliable to insure that random component failures or malfunctions would not result in ATWS events. The effects of anticipated transients with failure to trip are not considered in the design bases of the DCPP. Nevertheless, in accordance with the final NRC ATWS rule; 10CFR50.62(b) “Requirements for Reduction of Risk from Anticipated Transients Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants,” (Ref 1) an ATWS Mitigation System Actuation Circuitry (AMSAC) is installed at Diablo Canyon Power Plant.

ATWS equipment required by 10 CFR 50.62 and addressed by the WOG ATWS Licensing Topical Report is described in the following DCPP FSAR sections:

- FSAR 7.6.1.4 ATWS Mitigation System Actuation Circuitry (AMSAC)- (Ref. 7)

<u>Westinghouse Topical Report</u>

The Westinghouse Owner’s Group (WOG) developed a conceptual design generic to Westinghouse plants, Westinghouse Topical Report WCAP-10858, AMSAC Generic Design package (Ref 4) to generically address the hardware aspects of meeting the ATWS Rule. On July 7, 1986 the NRC issued the Safety Evaluation of the Westinghouse Topical Report concluded that the WCAP-10858 Westinghouse Licensing Topical Report adequately meets the requirements of 10 CFR 50.62. The approved version of the WCAP is labeled WCAP-10858-P-A (Ref 4). On August 15, 1988 the NRC issued the Safety Evaluation of the AMSAC System, PG&E Proposed Methods of Implementing the Requirements of 10 CFR 50.62 (AWTS) for Diablo Canyon (Ref. 2).

3.0 SYSTEMS AND STRUCTURES REQUIRED TO COMPLY WITH ATWS

In response to an ATWS event, the AMSAC automatically initiates auxiliary feedwater flow, isolates Steam Generator blowdown and sample lines and initiates a turbine trip. Systems and structures required to mitigate an ATWS Event are presented in the following sections:

- Section 3.1 – ATWS – Mitigation System Actuation Circuitry (AMSAC)
- Section 3.2 – ATWS – Mitigation Support System
- Section 3.3 – Structures

3.1 ATWS – Mitigation System Actuation Circuitry

The following equipment is required to perform during an ATWS event:

- Plant Protection System
  The AMSAC receives isolated, non-safety-related, steam generator narrow range level and turbine first stage pressure analog signals from the plant protection system.

- ATWS Mitigation System Actuation
  The AMSAC actuation outputs go to the main turbine trip, the main turbine backup trip circuits and the motor driven auxiliary feedwater control circuits.

3.2 ATWS – Mitigation Support Systems

The following support SSCs are credited in the ATWS Mitigation System

- Auxiliary Feedwater System
  The AMSAC provides logic signals to start the auxiliary feedwater pumps on low-low steam generator level. The auxiliary feedwater control circuits supply signals to the steam generator blowdown and sample line containment isolation valves

- Lube Oil
  The AMSAC provides logic signals to trip the main turbine on low-low steam generator level.

- 120 V AC System
  The 120 volt ac system provides non-vital uninterruptible power to the AMSAC.

- 125 V DC System
  The 125 volt dc system provides non-vital uninterruptible power to the AMSAC.

- Plant Protection System
  The AMSAC receives isolated, non-safety-related, steam generator narrow range level and turbine first stage pressure analog signals from the plant protection system.

  Steam Generator Narrow Range Level Instrumentation
  There are four steam generator narrow range level transmitters (LT-517, LT-528, LT-539, LT-549) that provide inputs to AMSAC.

  Main Turbine First Stage Pressure
  There are two main turbine first stage pressure indicators (PT-505, PT-506) that provide inputs to AMSAC. The tubing associated with PT-505, -506 runs in the Turbine Building from the transmitters located in the CCW Heat Exchanger vaults on El. 85' up to the HP turbines on El. 140'. Per DCM S-04, the transmitters provide redundant first stage impulse pressure input from the HP turbine to the reactor trip circuit, provide input to the main steam dump control circuitry, provide input to ATWS Mitigation

System Actuation Circuitry (AMSAC), and are fail-safe. Per DCM S-34B, AMSAC provides a way to trip the main turbine, initiate auxiliary feedwater flow and isolate steam generator blowdown in the event that an ATWS results in the loss of the secondary heat sink. After discussions with the turbine engineer, AMSAC system owner, and former Senior Reactor Operators, it was determined by DCPP that the tubing is not required to shut down the reactor and maintain it in a safe shutdown condition, nor is it required to prevent or mitigate the consequences of accidents that could result in potential offsite exposure. A drop in pressure, or equivalent reading, will result in AMSAC initiating a reactor trip that will bring the plant to a safe shutdown condition.

3.3 STRUCTURES

Plant structures provide physical support and protection for systems or components that either penetrate the structure wall or are supported by the structure wall, floor, and roof. Direct interface is through the system or component supports that are anchored to the structure. The DCPP plant structures that provide physical support and protection for systems that are credited for compliance with the ATWS Rule are the following

- Containment Building
- Auxiliary Building
- Control Room (Located in the Auxiliary Building but separate LRID)
- Turbine Building

3.4 CASCADING OF SYSTEMS

First-level, primary support systems (or structures) that are necessary for the functioning of equipment credited to mitigate an ATWS event or otherwise demonstrate compliance with 10 CFR 50.62 "ATWS" are included within the scope of 10 CFR 54. To comply with the License Renewal Rule, 10 CFR 54.4(a)(3), second-, third- and fourth-level support systems, back-up systems, and systems or structures not explicitly credited in a current licensing basis (CLB) document to be available during this regulated event, are not considered.

3.5 TABLE 3-1 AND TABLE 3-2

For the purpose of determining the systems and structures within the scope of license renewal per 10 CFR 54.4(a)(3), those systems that are required for an ATWS event are listed in Table 3-1, and the associated structures are listed in Table 3-2. Each table will include the following columns:

Table 3-1

- System – system designator identified in TR-9DC LRID column
- System Name – system name identified in TR-9DC
- System Function – license renewal intended function for regulated event
- CLB Reference – Reference number from Section 4 (Reference Section) of position paper to be noted. As necessary a specific section of the reference may be identified

Table 3-2

- Structure – structure designator identified in TR-9DC LRID column
- Structure Name – structure name identified in TR-9DC
- Structure Function – license renewal intended function for regulated event
- CLB Reference – Reference number from Section 4 (Reference Section) of position paper to be noted. As necessary a specific section of the reference may be identified

4.0 REFERENCES

1. 10 CFR 50.62, "Requirement for the reduction of risk from anticipated transients without scram (ATWS) events for light-water-cooled nuclear power plants"
2. USNRC Letter to PG&E, Safety Evaluation of the AMSAC System, PG&E's Method of Implementing the Requirements of 10 CFR 50.62 (ATWS) for Diablo Canyon, dated August, 15, 1988 (Ref PG&E ACTS log 1705)
3. DCPP FSAR Section 6.5.5, Rev 17, "Instrumentation Requirements"
4. WCAP-10858-P-A, "Westinghouse Topical Report AM SAC Generic Design Package"
5. WCAP-8330, "Westinghouse Anticipated Transients Without Reactor Trip Analysis," August 1974.
6. DCM No. S-38B, ATWS Mitigation System Actuation Circuitry (AMSAC)
7. DCPP FSAR Section 7.6.1.4, Rev 17, "ATWS Mitigation System Actuation Circuitry (AMSAC)
8. DCL-87-258, Diablo Canyon Units 1 and 2 Plant-Specific AMSAC Design, October 30, 1987
9. DCPP FSAR Section 6.5.2.1.2, Rev 17, "Auxiliary Feedwater Pumps and Controls
10. DCPP FSAR Section 4.3.1.7, Rev 17, "Anticipated Transients Without Scrams
11. DCPP FSAR Section 7.6.2.4, Rev 17, ATWS Mitigation System Actuation Circuitry (AMSAC)
12. DCM S-65, R1, 120VAC System

TABLE 3-1
Systems Relied upon to Demonstrate Compliance with 10 CFR 50.62

Sys	System Name	System Function	CLB Reference
03B	Auxiliary Feedwater	ATWS Mitigation Support AMSAC initiates auxiliary feedwater flow	Ref. 7 Ref 2 Section 3.3 Ref 9
04	Main Steam	ATWS Mitigation Provides turbine first stage pressure signal	Ref. 7 Ref. 2
20	Lube Oil	ATWS Mitigation AMSAC initiates turbine trip signal.	Ref 7
35	AMSAC	ATWS Mitigation AMSAC initiates auxiliary feedwater flow and trips the turbine	Ref. 7
38	Solid State Protection	ATWS Mitigation Provides steam generator narrow range level and turbine first stage pressure analog signals.	Ref 7 Ref 2
65	120V AC	ATWS Mitigation Support provides non-vital uninterruptible power to the AMSAC.	Ref 2 Section 3.2
67	120V DC	ATWS Mitigation Support provides non-vital uninterruptible power to the AMSAC.	Ref 12 Sections 4.3.2 and 4.3.3.4

TABLE 3-2
Structures Relied upon to Demonstrate Compliance with 10 CFR 50.62

Struct.	Structure Name	Structure Function	CLB Reference
ZA	Auxiliary Building	Physical Support and Protection Provides physical support and protection for components relied upon to demonstrate compliance with ATWS.	Ref. 8 Response 11
ZC	Containment	Physical Support and Protection Provides physical support and protection for components relied upon to demonstrate compliance with ATWS.	Ref.7
ZJ	Control Room (located in Auxiliary Building)	Physical Support and Protection Provides physical support and protection for components relied upon to demonstrate compliance with ATWS.	Ref. 8 Response 5
ZT	Turbine Building (Includes the Emergency Diesel Generator Rooms)	Physical Support and Protection Provides physical support and protection for components relied upon to demonstrate compliance with ATWS	Ref. 8 Response 13

PAM COB Procedure Cover Sheet

Guidance for Scoping and Screening of Heat Exchangers

PAMCOBP – DG-4 – 02/07 – Rev 2

Revision Summary:

Revision 0 – Initial Issue
Revision 1 – see page ii
Revision 2 – see page ii

Prepared by: Eric Blocher

Approved by: Paul F Crawley

Date Approved: 08 Feb 07

Desktop Guide DG-4

Guidance for Scoping and Screening of Heat Exchangers for STARS License Renewal Projects

Revision 2

February 8, 2007

WorleyParsons

Guidance for Scoping and Screening of Heat Exchangers for Stars License Renewal Project

Approval Page

Revision	Prepared by:	Approved by:	Date
0	Gary Warner	Eric Blocher	11/16/04
1	Gary Warner	Eric Blocher	11/18/04
2	Tony Grenci	Eric Blocher	02/08/07

Revision Summary

Revision	Required Changes to Achieve Revision	Date
0	Initial Issue	Nov. 14, 2004
1	Clarify Section 3.0 Definitions	Nov. 18, 2004
2	Updated for NUREG-1801 and NEI 95-10 revisions. Added guidance for bolting components, assignment of component numbers in LRDMT, coiling coil spatial interactions, and fin environments. Deleted guidance for criterion (a)(2).	Feb. 08, 2007

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Guidance for Adding Heat Exchanger Components

1.0 Purpose

Provides instruction on how to add Heat Exchanger components during Component Scoping and Screening of mechanical systems performed in accordance with reference 2.1.

2.0 References:

2.1 Project Instruction-1, Scoping and Screening of Systems, Structures, and Components, Current Revision

2.2 NUREG 1801 "Generic Aging Lessons Learned (GALL) Report" Revision 1, September 2005

2.3 NEI 95-10 Appendix D "Standard License Renewal Application Format" May 2005

3.0 Definitions:

3.1 Heat Exchanger Shell Side: The "Heat Exchanger Shell Side" includes the subcomponent(s) internally exposed to the shell side environment. The portions of the tubes and tube sheets exposed to the shell side environment are evaluated as Heat Exchanger Tube Side components.

3.2 Heat Exchanger Tube Side: The "Heat Exchanger Tube Side" includes the tubes, the channel head, the tube sheets and the fins where applicable. The portions of the tubes and tube sheets exposed to the shell side environment are included by assigning the shell side environment as the external environment for these components.

4.0 Instructions:

Add Heat Exchanger components as described below:

Step 1: For a given In-Scope heat exchanger equipment number, determine the configuration, intended functions, environments and materials for the heat exchanger components. The major components may include the following:

- Shell
- Tubes
- Head (channel head)
- Tube Sheets
- Fins

Any bolting associated with the heat exchanger can be assumed to be covered by any identical generic bolting component(s) for the affected LRID. Create a separate bolting component only if the heat exchanger bolting is not bounded by the generic bolting component.

Step 2: Create another heat exchanger plant equipment number record for each subcomponent of the heat exchanger that will result in an additional intended function/material/environment combination as determined in step 1. Revise the component number and the name to distinguish the major heat exchanger subcomponents as necessary. Create only as many total rows as necessary to encompass all intended function/material/environment combinations. You may not need as many subcomponents as shown in the example below. The Description for the original component cannot be revised. Indicate specific usage in the Comment field instead.

Cmp No (dc)	Cmp Name (dc)	Plt Sys	Cmp Type
EEC01A	FUEL POOL COOLING HEAT EXCHANGER	EC	HEAT EXCHANGER
EEC01A-01	FUEL POOL COOLING HEAT EXCHANGER Tubes	EC	HEAT EXCHANGER
EEC01A-02	FUEL POOL COOLING HEAT EXCHANGER Head	EC	HEAT EXCHANGER
EEC01A-03	FUEL POOL COOLING HEAT EXCHANGER Tubesheet	EC	HEAT EXCHANGER

Step 3: Coordinate with the Mechanical discipline lead and the LDRMT manager to revise the component type to refer to that specific heat exchanger as shown below.

Cmp No (dc)	Cmp Name (dc)	Plt Sys	Cmp Type
EEC01A	FUEL POOL COOLING HEAT EXCHANGER	EC	HEAT EXCHANGER (FUEL POOL COOLING HEAT EXCHANGER)
EEC01A-01	FUEL POOL COOLING HEAT EXCHANGER Tubes	EC	HEAT EXCHANGER (FUEL POOL COOLING HEAT EXCHANGER)
EEC01A-02	FUEL POOL COOLING HEAT EXCHANGER Head	EC	HEAT EXCHANGER (FUEL POOL COOLING HEAT EXCHANGER)
EEC01A-03	FUEL POOL COOLING HEAT EXCHANGER Tubesheet	EC	HEAT EXCHANGER (FUEL POOL COOLING HEAT EXCHANGER)

Step 4: Check the LR, Passive and Long Lived (LL) box. Assign the intended function(s) that apply. Potential examples are as follows:

- Shell FM01 (Pressure Boundary) or FM08 (Spatial Interaction)
- Head FM01 (Pressure Boundary) or FM08 (Spatial Interaction)
- Tube Sheets FM01(Pressure Boundary)
- Tubes FM01 (Pressure Boundary) and FM04 (Heat Transfer)
- Fins FM04 (Heat Transfer)

- Coil FM08 (Spatial Interaction)

Step 5: Assign internal and external environments to each of the component records. Some considerations include:

- The internal environment for tubes is the tube side environment and the external environment is the shell side environment.
- The internal environment for the tubesheet is the tube side environment and the external environment is the shell side environment.
- The internal environment for fins is N/A and the external environment is normally the shell side environment.

Cmp No (dc)	Cmp Name (dc)	Env Int	Env Ext
EEC01A	FUEL POOL COOLING HEAT EXCHANGER	Closed Cycle Cooling Water	Plant Indoor Air
EEC01A-01	FUEL POOL COOLING HEAT EXCHANGER Tubes	Primary Coolant	Closed Cycle Cooling Water
EEC01A-02	FUEL POOL COOLING HEAT EXCHANGER Head	Primary Coolant	Plant Indoor Air
EEC01A-03	FUEL POOL COOLING HEAT EXCHANGER Tubesheet	Primary Coolant	Closed Cycle Cooling Water

Step 6: Assign the material type and material reference to each of the components record.

Cmp No (dc)	Cmp Name (dc)	Material
EEC01A	FUEL POOL COOLING HEAT EXCHANGER	Carbon Steel
EEC01A-01	FUEL POOL COOLING HEAT EXCHANGER Tubes	Stainless Steel
EEC01A-02	FUEL POOL COOLING HEAT EXCHANGER Head	Stainless Steel
EEC01A-03	FUEL POOL COOLING HEAT EXCHANGER Tubesheet	Stainless Steel

Diablo Canyon Power Plant License Renewal

TR-4DC

Environmental Qualification (EQ)
License Renewal Position Paper

Revision 1~~0~~

~~September 01, 2007~~April 3, 2009

EQ License Renewal Position Paper
Diablo Canyon Power Plant

Approval Page

Revision	Prepared by:	Reviewed by:	Approved by:
0	Matthew Shepard	Paul Johnson Gary D. Warner	Eric Blocher
Date	August 9, 2007	August 15, 2007	September 01, 2007
1	Stan Shepherd		
Date	April 3, 2009		

Open Items:

1. None

Revision Summary

Revision	Required Changes to Achieve Revision	Date
0	Initial Issue	9/01/2007
1	Incorporated PCTF #28 which clarified that System 23 consists of separate LRIDs in Section 3.0 and Table 3-1. Incorporated PCTF #35 which, for System 48 (Incore Flux Mapping), changed the System Function, changed a reference and added a new reference in Table 3-1.	4/3/2009

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1.0 PURPOSE OF POSITION PAPER

The License Renewal Rule, 10 CFR 54.4(a)(3) (Ref. 1), requires that the structures, systems, and components (SSC's) relied on in safety analyses or plant evolutions to perform a function that demonstrates compliance with the Commission's regulations for environmental qualification (10 CFR 50.49) be identified. The scope of the 10 CFR 50.49 equipment to be identified within the scope of 10 CFR 54.4(a)(3) is that equipment already identified under 10 CFR 50.49(b).

This position paper identifies the Diablo Canyon systems and structures relied upon to demonstrate compliance with 10 CFR 50.49, "Environmental Qualification" (Ref. 2). This document is for the use of license renewal project personnel engaged in the preparation, review, or approval of scoping and screening evaluations in support of license renewal feasibility activities for Diablo Canyon.

2.0 EQ CURRENT LICENSING BASIS (CLB) REQUIREMENTS FOR DIABLO CANYON

Specific requirements pertaining to qualification of important to safety electric equipment located in harsh environment are contained in 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants." Regulatory Guide 1.89, Rev 1 (Ref. 3), "Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants," supports 10 CFR 50.49. The EQ rule (10 CFR 50.49) is based on the Division of Operating Reactors Guidelines and NUREG-0588 (Ref. 4). The new or replacement equipment qualified to NUREG-0588 Category I will be reviewed for the period of extended operation to assess the validity of the extended qualification to the requirements of Section 4 of NUREG-0588.

2.1 EQ Regulatory Requirements

EQ Rule Requirements

Each holder of a license for a nuclear power plant must establish a program for qualifying the electrical equipment important to safety. This program, the Environmental Qualification (EQ) program, includes safety-related electric equipment, non-safety-related electric equipment whose failure under postulated environmental conditions could prevent satisfactory accomplishment of safety functions of the safety-related equipment, and certain post-accident monitoring equipment, as defined in 10 CFR 50.49 (b)(1), 10 CFR 50.49 (b)(2), and 10 CFR 50.49 (b)(3) respectively.

2.2 Diablo Canyon Environmental Qualification CLB

The updated Final Safety Analysis Report (FSAR) Section 3.11 (Ref. 5) declares that 10 CFR 50.49 is the governing regulation for the EQ program at Diablo Canyon Power Plant (DCPP). Pacific Gas and Electric (PG&E) has certified its compliance with this regulation as required by NRC Generic Letter 84-24, "Certification of Compliance to 10 CFR 50.49, Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants" (Ref. 6). The PG&E certification is documented in letter DCL-85-072 to the NRC dated February 22, 1985 (Ref. 7). The scope of the EQ program at DCPP is limited to plant areas exposed to harsh environmental conditions following a design basis accident (DBA) or during normal operation. The following post-accident conditions constitute the parameters employed in defining a harsh environment as covered under the DCPP EQ program (Ref. 8):

1. Pressure, temperature, humidity, and chemical spray inside containment after a Loss of Coolant Accident (LOCA) or a Main Steam Line Break (MSLB)

2. Expected pressure, temperature and humidity outside containment after a High Energy Line Break (HELB)

3. Flooding inside and outside containment following a Medium Energy Line Break (MELB) or a HELB

4. Time integrated radiation doses inside containment following a LOCA

5. Expected time integrated radiation doses outside containment following a LOCA when the Emergency Core Cooling System (ECCS) is placed in the recirculation mode of safety injection

Procedure CF3.ID3 Section 1.4 (Ref. 9) states that items addressed in accordance with 10 CFR 50, Appendix A, "General Design Criteria for Nuclear Power Plants" (Ref. 10) are outside the scope of 10 CFR 50.49, and thus not covered under the EQ program. These include dynamic and seismic qualification of electric equipment important to safety, natural phenomena, external events and localized effects such as jet impingement from a HELB. During normal operation the parameters that define a harsh environment encompass pressure, temperature, humidity, and radiation levels inside and outside containment (Ref. 8).

The six functions required for accident mitigation by the environmentally qualified electrical equipment are (1) emergency reactor shutdown, (2) containment isolation, (3) reactor core cooling, (4) containment heat removal, (5) core residual heat removal, and (6) prevention of a significant release of radioactive material to the environment. In addition to the class 1E equipment that perform these safety related functions, equipment located in harsh environments whose failure would prevent accomplishment of safety-related components and certain post accident monitoring equipment are also environmentally qualified.

3.0 SYSTEMS AND STRUCTURES REQUIRED TO COMPLY WITH EQ FOR LICENSE RENEWAL

To facilitate maintaining the DCPP EQ Master List (EQML) as a living document, specific fields in the Component Database in the Plant Information Management System (PIMS) pertaining to EQ equipment along with Controlled Drawing 050909 comprise the EQML

(Ref. 11 and Ref. 12). A system is environmentally qualified if it has a component listed in the EQML and does not have notes N11, N15, N16 or N22 under the ENVIR FILE field in PIMS as described in Controlled Drawing 050909. These notes represent specific instances for the electrical components included in the EQML that are outside the scope of the DCPP EQ program. The systems required to comply with EQ for License Renewal, based on the previous requirements, are as follows:

03 – Main Feedwater	12 – Containment Spray
03B – Auxiliary Feedwater	14 – Component Cooling Water
04 – Turbine Steam Supply	19 – Liquid Radwaste
06 – Auxiliary Steam	23 – HVAC (Containment and Aux building) See LRID breakdown in Table 3-1.
07 – Reactor Coolant	25 – Compressed Air
08 – Chemical and Volume Control	37 – Nuclear Instrumentation
09 – Safety Injection	45 – Containment Structure and Isolation Valves
10 – Residual Heat Removal	48 – Incore Flux Mapping
11 – Nuclear Steam and Supply	

3.1 TABLE 3-1

For the purpose of determining the systems and structures within the scope of license renewal per 10 CFR 54.4(a)(3), those systems that are required for EQ are listed in Table 3-1. Each component in the EQ program has an EQ file that contains the full set of necessary descriptive information. Table 3-1 lists the EQ file codes that cover the components of each system.

Table 3-1

- System Id. – system Id identified in the DCPP Maintenance scoping document system.
- System Name – system name identified in the DCPP Maintenance scoping document system.
- Function - Function required for accident mitigation
- CLB Reference – Reference number from Section 4 (Reference Section) of Position Paper to be noted. As necessary a specific section of the reference may be identified.

4.0 REFERENCES

1. Title 10, United States Code of Federal Regulations, Energy, Part 54 (10 CFR 54). "Requirements for renewal of Operating Licenses for Nuclear Power Plants"

2. Title 10, United States Code of Federal Regulations, Energy, Part 50.49 (10 CFR 50.49). "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants"

3. US NRC Regulatory Guide 1.89. "Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants." June 1984

4. US NRC NUREG-0588. "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment." July, 1981

5. DCPP Updated Final Safety Analysis Report (FSAR)

6. NRC Generic Letter 84-24, "Certification of Compliance to 10 CFR 50.49, Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants," dated December 27, 1984

7. PG&E (Mr. J.D. Shiffer) letter DCL-85-072 to NRC (Mr. Darrell G. Eisenhut, Director, Division of Licensing, Office of Nuclear Reactor Regulation) dated February 22, 1985, re: "Response to NRC generic Letter 84-24."

8. DCPP Design Criteria Memorandum T-20 Revision 8, Environmental Qualification, PG&E.

9. CF3.ID3 Revision 6, "Environmental Qualification Program"

10. Title 10, United States Code of Federal Regulations, Energy, Part 50 Appendix A (10 CFR Appendix A). "General Design Criteria for Nuclear Power Plants"

11. Environmental Qualification Master List, Component Database Module of the DCPP Plant Information System (PIMS)

12. Controlled Drawing 050909 Revision 31

13. Calculation EZ-02 Revision 4, "Environmental Qualification Requirements"

~~PIMS (Plant Information Management System)~~

14.

15. EQ File EH25B, "Whittaker & Combustion Engineering/Westinghouse Incore Thermocouple Connector Assembly," Revision 5

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TABLE 3-1
Systems Relied upon to Demonstrate Compliance with 10 CFR 50.49

System Id	System Name	Function	CLB Reference
03	Main Feedwater	Containment Isolation Core Residual Heat Removal Prevention of Radioactive Release	Ref. 5, Sections 6.5.1 and 6.2.4
03B	Auxiliary Feedwater	Containment Isolation Core Residual Heat Removal Prevention of Radioactive Release	Ref. 5, Sections 6.5.1 and 6.2.4
04	Turbine Steam Supply	Containment Isolation Core Residual Heat Removal Prevention of Radioactive Release	Ref. 5, Sections 10.2.2, 10.2.4, and 11.2.2
06	Auxiliary Steam	Containment Isolation Core Residual Heat Removal Prevention of Radioactive Release	Ref. 5, Section 7.6.2
07	Reactor Coolant	Emergency Reactor Shutdown Containment Isolation Reactor Core Cooling Core Residual Heat Removal Prevention of Radioactive Release	Ref. 5, Sections 5.1 and 5.5.1
08	Chemical and Volume Control	Emergency Reactor Shutdown Containment Isolation Reactor Core Cooling Prevention of Radioactive Release	Ref. 5, Sections 4.2.3, 5.2.3, and 5.5.3
09	Safety Injection	Emergency Reactor Shutdown Containment Isolation Reactor Core Cooling Prevention of Radioactive Release	Ref. 5, Sections 5.2.1, 5.5.3 and 6.5.1
10	Residual Heat Removal	Containment Isolation Reactor Core Cooling Core Residual Heat Removal Prevention of Radioactive Release	Ref. 5, Section 5.5.6
11	Nuclear Steam and Supply	Containment Isolation Prevention of Radioactive Release	Ref. 5, Section 9.3.2
12	Containment Spray	Containment Isolation Containment Heat Removal Prevention of Radioactive Release	Ref. 5, Sections 6.2.1 and 6.2.2
14	Component Cooling Water	Emergency Reactor Shutdown Containment Isolation Core Residual Heat Removal Prevention of Radioactive Release Containment Heat Removal Reactor Core Cooling	Ref. 5, Section 9.2.2
19	Liquid Radwaste	Containment Isolation Prevention of Radioactive Release	Ref. 5, Section 11.2.2

System Id	System Name	Function	CLB Reference
23	HVAC (Containment and Aux building): LRID 23A: Containment Ventilation and H2 Control LRID 23B: Auxiliary Bldg. Ventilation LRID 23F: Control Room Area Ventilation	Emergency Reactor Shutdown Reactor Core Cooling Containment Heat Removal Core Residual Heat Removal Prevention of Radioactive Release	Ref. 5, Sections 9.4.1 and 9.4.2
25	Compressed Air	Containment Isolation Prevention of Radioactive Release	Ref. 5, Section 9.3.1
37	Nuclear Instrumentation	Emergency Reactor Shutdown Containment Isolation Prevention of Radioactive Release Reactor Core Cooling	Ref. 5, Sections 7.2.1 and 7.7.1
45	Containment Structure and Isolation Valves	Containment Isolation Prevention of Radioactive Release Core Residual Heat Removal Reactor Core Cooling Containment Heat Removal Emergency Reactor Shutdown	Ref. 5, Sections 6.1.2, 6.2.1, and 6.2.4
48	Incore Flux Mapping	~~Pressure Boundary (Electrical Penetrations)~~Post Accident Monitoring Thermocouple circuit	Ref. 13, Section 7.1.5 Ref. 154

Diablo Canyon License Renewal

TR-5DC

Pressurized Thermal Shock (PTS)
License Renewal Position Paper

Revision 1

June 13, 2009

PTS License Renewal Position Paper
Diablo Canyon Units 1 and 2

Approval Page

Revision	Prepared by:	Checked By:	Approved by:
0	David Boortz	Bill Bojduj Don Stevens	Eric Blocher
Date	2/7/07	Aug. 16, 2007	Aug. 22, 2007
1	Stan Shepherd	M. Albright D. Lynch	David Kunsemiller
Date	April 3, 2009	June 1, 2009	June 13, 2009

Open Item:

- Closed

Revision Summary

Revision	Required Changes to Achieve Revision	Date
0	Initial Issue	8/22/07
1	Incorporated PCTF #45 which added a Note to Section 3.2. Also updated references and incorporated DCPP Calc File N-306 (see ref.17). Closed open item reflecting current status of the rule change.	4/3/2009

TABLE OF CONTENTS

1.0 PURPOSE OF POSITION PAPER

The license renewal rule, at 10 CFR 54.4(a)(3), requires that the licensee evaluate all structures, systems, and components (SSCs) relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for pressurized thermal shock (PTS, 10 CFR 50.61).

The Diablo Canyon Unit 1 and 2 reactor pressure vessels are the only components relied upon to demonstrate compliance with 10 CFR 50.61, "Fracture toughness requirements for protection against pressurized thermal shock events." This position paper states the basis for that limitation of scope. This document is for the use of License Renewal Project personnel for preparation, review, or approval of scoping and screening evaluations in support of license renewal activities for Diablo Canyon Power Plant (DCPP).

2.0 PTS CURRENT LICENSING BASIS (CLB) REQUIREMENTS FOR DIABLO CANYON

> A Pressurized Thermal Shock Event is an event or transient in pressurized water reactors (PWRs) causing severe overcooling (thermal shock) concurrent with or followed by significant pressure in the reactor vessel.

[10 CFR 50.61(a)(2)]

The probability of a PTS event is very low. A PTS event is commonly classified as "beyond design basis." No response to a PTS event is included in the Diablo Canyon FSAR descriptions of safety analyses.

2.1 PTS Regulatory Requirements

<u>PTS Rule Requirements</u>

The PTS rule applies only to pressurized water reactors (PWRs).

The PTS rule was first introduced, and began to be imposed on licensees and applicants for licenses, within NUREG-0737 TMI Lessons Learned requirements as Unresolved Safety Issue A-49. See "History and Development of the Current Licensing Basis," below.

On July 23, 1985 the NRC issued an amendment to 10 CFR 50.61(b). The amended 10 CFR 50.61 "Fracture toughness requirements for protection against pressurized thermal shock events" (the PTS rule) required each pressurized water reactor licensee to calculate the end-of-life (EOL) nil-ductility transition reference temperature parameter RT_{PTS} for each reactor vessel material heat subject to neutron embrittlement, compare them to screening criteria, and if a criterion was exceeded, to initiate appropriate compensatory measures. The rule has since been amended in detail (last at 61 FR 39300, 29 July 1996) but the requirements remain substantially the same.

The PTS rule requires, first, that pressurized water reactor pressure vessels be evaluated for susceptibility to brittle failure if a PTS event occurs. If RT_{PTS} for each heat of material of the reactor pressure vessel does not exceed 270 ºF for plates, forgings, and axial welds; or 300 ºF for circumferential welds (the PTS screening criteria), only the reactor pressure vessel is “relied on to demonstrate compliance” with the 10 CFR 50.61 PTS rule.

If the reactor pressure vessel materials cannot meet these end-of-life RT_{PTS} screening criteria, 10 CFR 50.61(b)(3) requires “…flux reduction measures that are reasonably practicable…,” and if the vessel still fails to demonstrate acceptable end-of-life RT_{PTS} with the predicted flux reductions,

> …the licensee shall submit a safety analysis to determine what, if any, modifications to equipment, systems, and operation are necessary to prevent potential failure of the reactor vessel as a result of postulated PTS events if continued operation beyond the screening criterion is allowed.

[10 CFR 50.61(b)(4)]

Therefore, if the PTS screening criteria are met, only the reactor vessel is relied on to mitigate possible PTS events (i.e., is in the scope of the PTS rule). However, if additional structures, systems, and components or modifications to them support flux reduction measures, or are relied on by a plant-unique safety analysis to demonstrate an acceptable level of risk, or to support operating changes required to support the safety analysis, these structures, systems and components then also fall within the scope of the rule.

10 CFR 50.61(b)(1) requires a re-evaluation of RT_{PTS} “…whenever there is a significant change in projected values of RT_{PTS}, or upon a request for a change in the expiration date for operation of the facility.” License renewal therefore requires the re-evaluation of RT_{PTS}, with fluence projections to the end-of-life-extended (EOLE) even if the expected change is not significant.[1]

The 1995 amendment to the rule identified thermal annealing as an acceptable method for mitigating neutron irradiation embrittlement effects and for reducing RT_{PTS} [10 CFR 50.61(b)(7)]; and incorporated the Reg Guide 1.99 Revision 2 methods for determining unirradiated $RT_{NDT(U)}$ and the margin term, and its definition

[1] “Changes to RT_{PTS} values are considered significant if either the previous value or the current value, or both values, exceed the screening criterion prior to the expiration of the operating license, including any renewed term, if applicable for the plant” [10 CFR 50.61, Footnote 2].

of “credible” surveillance data (Reference 5, incorporated in 10 CFR 50.61(a)(5), (c)(1), and (c)(2)(i)). Reference 14 contemplated annealing the Unit 1 vessel, but this is no longer contemplated at Diablo Canyon.

2.2 Diablo Canyon Pressurized Thermal Shock CLB

2.2.1 FSAR

A search of the Diablo Canyon FSAR for “thermal shock,” “50.61,” and "PTS," yielded only references that were unrelated to PTS values and GL 92-01. The search results included a table comparing 40 year operating year values to generic 10 CFR "50.61" values.

2.2.2 History and Development of the Current Licensing Basis

A required response to “PTS Rule Requirements,” from all PWR licensees became effective as a federal regulation with the July 23, 1985 amendment to 10 CFR 50.61(b). Diablo Canyon Power Plant first responded in January 1986 (Reference 18), and again in April 1986 (Reference 19) to which the NRC issued an approving safety evaluation (Reference 8)

In June 1992 DCPP responded to the Generic Letter, GL 92-01, and submitted a supplemental letter in December of the same year (References 9 and 10). The NRC released a Supplement to GL 92-01, to which DCPP responded and provided a response to a "Request for Additional Information" (References 11, 12, and 13). Surveillance Capsule B is expected to be withdrawn during the current operating term after it has accumulated the fluence equivalent to the vessel inside surface at 54.8 EFPY, approximately 60 years of operation (Reference 20). Under the current PTS rule, Unit 1 will exceed the screening criteria after roughly 50 calendar years (Reference 14). The NRC is currently undergoing a PTS rulemaking plan that will expand the margins for PTS limits (Reference 15). The rule change will not be in place in time to be useful for the LRA.

Fluence data from Unit 2 surveillance capsule V exceeds the projected fluence for the EOLE for DCPP Unit 2. The screening criteria for the current PTS rule are not exceeded by Unit 2 for more than 60 years of operation, and therefore is not an issue of concern (Reference 14). To widen the operation margin for PTS limits, DCPP may adopt the new PTS rule change for Unit 2 as well.

An embrittlement analysis was done on DCPP Units 1 and 2 reactor vessels. Based on a capacity factor of 98% (including refueling outages) and utilizing fluence projection based on the latest Westinghouse transport theory model, the DCPP Unit 2 vessel can be operated for 54 EFPY without exceeding the RTpts screening criteria for EOLE with no flux reduction measures (Reference 17). This would be more than 20 calendar years beyond the current license expiration date. The DCPP Unit 1 reactor, under the same analysis, can operate for 42 EFPY, which is 10 calendar years beyond the current license expiration date (Reference 17). This analysis demonstrates license extension is possible for Unit 2 with no change in PTS scope; however, Unit 1 will exceed the PTS screening criteria, under the current PTS rule before reaching its EOLE.

2.2.3 Related Licensing Bases Not Included Here

This summary does not include all NRC information requests, DCPP responses, and NRC evaluations of those responses, concerning Generic Letter 92-01 (GL 92-01) and its supplements (Reference 7). This GL requested that licensees review and report new or additional data pertinent to reactor vessel embrittlement. The primary concerns were material chemistry and its effect on projected embrittlement parameters, particularly

- Upper shelf energy (USE)
- Operating pressure- temperature limits (P-T curves)
- Low-temperature overprotection limits (LTOP limits)
- Nil-ductility transition reference temperature (RT_{NDT}), and
- Nil-ductility transition reference temperature for pressurized thermal shock screening (RT_{PTS}).

This position paper deals directly only with effects of these surveys on the Diablo Canyon RT_{PTS} calculations.

2.2.4 Conclusion

RT_{PTS} for DCPP Unit 1 will exceed the PTS screening criteria under the current PTS rule at roughly 42 EFPY. DCPP Unit 2 will not exceed PTS limits under the current rule for more than 60 calendar years (Reference 17). Unit 1 will require that flux reduction measures be developed and submitted to the NRC for approval in accordance with 10CFR50.61(b) at least 3 years prior to exceeding the PTS screening criteria. For the LRA, a feasibility study is required to demonstrate that there is time to implement reasonable flux reduction measures are available such that the PTS screening value will not be exceeded before reaching EOLE. Both units will require that the fluence values and projected PTS values be provided for the extended belt-line materials to demonstrate that the extended belt-line materials have not reached a limiting value.

Therefore, only the reactor vessels are expected to be in scope for license renewal for PTS, and no other components should be added to the design basis for mitigation of PTS for the extended licensed operating period. See also “Basis for Limitation of Scope to the reactor Pressure Vessel” in Section 3.1, and for the submittal requirements for license renewal, Section 4.0, “License Renewal Application Requirements”.

3.0 SYSTEMS, STRUCTURES, AND COMPONENTS REQUIRED TO COMPLY WITH PTS FOR LICENSE RENEWAL

3.1 Systems and Components Required for PTS

Reactor pressure vessel integrity must be maintained in the event of a pressurized thermal shock. Reactor pressure vessel integrity is the *only* function which must be specifically maintained in response to a PTS event.

The license renewal rule, at 10 CFR 54.4(a)(3), states that

> "All systems, structures, and components relied on to demonstrate compliance with the Commission's regulations for … pressurized thermal shock (10 CFR 50.61)…"

—are within the scope of the license renewal rule. At Diablo Canton Units 1 and 2 reactor pressure vessels are the only components within the scope of the license renewal rule for PTS.

Basis for Limitation of Scope to the Reactor Pressure Vessel

NOTE:
The calculation of RT_{PTS} is a time-limited aging analysis (TLAA) as defined by 10 CFR 54.3(a), and is addressed in the TLAA Report and in Chapter 4 of the license renewal application.

If any reactor vessel material does not meet its applicable screening criterion, a reasonable flux reduction program, modifications, or operating changes must be initiated to reduce embrittlement effects. It is this flux reduction program, and these modifications or operating changes, which may require additional structures, systems, or components to meet requirements of the PTS rule. If these measures cannot reasonably be expected to reduce all projected RT_{PTS} values below the criteria, a safety analysis using alternative methods is required [10 CFR 50.61(b)(3) and (4)]. Regulatory Guide 1.154 describes the necessary analysis.

In 1986 an analysis was done to determine PTS values for Diablo Canyon Units 1 and 2 weld materials and base materials in the beltline region. This analysis was done for 40 EFPY and demonstrated that the RT_{pts} values for the base metal were less than 270F, and 300F for longitudinal welds. This analysis concluded that DCPP Unit 1 could operate for 80 EFPY and Unit 2 could operate for 128 EFPY (Reference 18).

In July 1998, PG&E submitted a letter that summarized PTS calculations and confirmed that Weld 3-442 C was limiting for Unit 1 and Plate B5454-2 was limiting for Unit 2. DCPP Unit 1 had an EOL PTS temperature of 258.4ºF and Unit 2 had an EOL PTS temperature of 210.9 ºF (Reference 13). These calculations demonstrate a projected operating term much shorter than that originally suggested by the analysis done in support of 1986 DCPP Letter DCL-86-006 (Reference 18).

Although the estimated period of operation, for which each Unit will meet the PTS screening criteria, has changed over the course of recalculating the PTS limits, the limiting material in DCPP Unit 1 and 2 has not changed. The most recent calculation under the current PTS rule estimates Unit 1 will be able to operate for 44 EFPY, and Unit 2 can operate beyond 54 EFPY. The NRC has proposed to update the PTS limits to widen the margin for EOL RT_{pts} (Reference 15). The new rule will not be issued in time to be of value for the DCPP LRA.

Other Systems, Structures, and Components Not Credited

The current licensing basis does not discuss use of any other structures, systems or components for mitigating a PTS event.

3.2 Structures Required for PTS

None. See "Other Systems, Structures, and Components Not Credited," next above. **Note: Component supports that are required to demonstrate compliance with PTS regulations are addressed in LRID ZSUP.**

4.0 LICENSE RENEWAL APPLICATION REQUIREMENTS

10 CFR 50.61(b)(1) requires a re-evaluation of RT_{PTS} "…whenever there is a significant change in projected values of RT_{PTS}, or upon a request for a change in the expiration date for operation of the facility." License renewal therefore requires the re-evaluation of RT_{PTS}, whether or not the change to RT_{PTS} will be "significant," and since the Diablo Canyon Unit 1 RT_{PTS} will exceed the screening value prior to reaching the EOLE, a flux reduction plan will be required to be described in the LRA. If future requirements or future analyses or evaluations of Diablo Canyon for pressurized thermal shock indicate that additional systems, structures, or components are required in order to ensure an adequate response to a PTS event, the additional systems, structures, and components will be evaluated in accordance with the regulations then in effect.

The calculation of RT_{PTS} is a time-limited aging analysis (TLAA) as defined by 10 CFR 54.3(a), and will be addressed in the TLAA Report and in Chapter 4 of the license renewal application.

5.0 REFERENCES

1. US NRC NUREG-1801 Vol. 1. "Generic Aging Lessons Learned (GALL) Report," Rev. 1, September, 2005.

2. Title 10, United States Code of Federal Regulations, Energy," Part 50, Section 61 (10 CFR 50.61). "Fracture toughness requirements for protection against pressurized thermal shock events." 60 FR 65468, Dec. 19, 1995, as amended at 61 FR 39300, 29 July 1996.

3. Title 10, United States Code of Federal Regulations, Energy," Part 50, Appendix G (10 CFR 50 Appendix G). "Fracture Toughness Requirements."

4. Title 10, United States Code of Federal Regulations, Energy," Part 54 (10 CFR 54). "Requirements for Renewal of Operating Licenses for Nuclear Power Plants."

5. US NRC Regulatory Guide 1.99. "Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events." Revision 2. May 1988.

6. US NRC Regulatory Guide 1.154. "Format and Content of Plant-Specific Pressurized Thermal Shock Safety Analysis Reports for Pressurized Water Reactors." January 1987.

7. US NRC Generic Letter 92-01 (GL 92-01). "Reactor Vessel Structural Integrity." Revision 1, Supplement 1. 19 May 1995.

8. NRC Letter 871030, October 30, 1987 "Fracture Toughness/Pressurized Thermal Shock."

9. PG&E Letter DCL-92-150 "Response to Generic Letter 92-01, Rev. 1, Reactor Vessel Structural Integrity." June 30, 1992.

10. PG&E Letter DCL-92-268 "Response to Generic Letter 92-01 Rev. 1, Reactor Vessel Structural Integrity" Supplemental Information December 4, 1992.

11. PG&E Letter DCL-93-227 "Response to NRC Request for Additional Information to Generic Letter 92-01, Revision 1." October 8, 1993.

12. PG&E Letter DCL-95-176 "Response to Generic Letter 92-01 Revision 1, Supplement 1, Reactor Vessel Structural Integrity." August 16, 1995.

13. PG&E Letter DCL-98-094 "Response to Request for Additional Information Regarding Reactor Pressure Vessel Integrity." July 6, 1998.

14. NPG Report, "Diablo Canyon Power Plant Reactor Vessel Embrittlement Management Plan," Chron #225683. January 10, 1995.

15. NRC Rulemaking Plan, 10 CFR 50.61. "Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events." Attached to SECY-06-0124, same title, May 26, 2006 (ADAMS Accession No. ML060530624).

16. Portney, Jeffrey intra company email, "PTS Screening Criteria," January 10, 2003, not otherwise retained for record.

17. PG&E Calc File N-306, Reactor Vessel Fluence Evaluation in Support of License Renewal," Revision 0, April 20, 2009.

18. PG&E Letter DCL-86-006 "Pressurized Thermal Shock Information Pursuant to 10 CFR 50.61," January 17, 1986.

19. PG&E Letter DCL-86-092 "Reactor Vessel Beltline Metal Composition and Fracture Toughness Properties," April 7, 1986.

20. Diablo Canyon Final Safety Analysis Report, Chapter 5.2, Table 5.2-22.

Diablo Canyon License Renewal

TR-11DC

Electrical Component Aging Evaluation
License Renewal Topical Report

Revision 0

January 26, 2010

Electrical Component Aging Evaluation
License Renewal Topical Report
Diablo Canyon Power Plant

Approval Page

Revision	Prepared by:	Reviewed by:	Approved by:	Owner Accepted
0	Kurt Lathrop 1/7/2010	George Kyle 1/7/2010	Dave Kunsemiller 1/26/10	Philippe Soenen 1/28/10

Revision Summary

Revision	Required Changes to Achieve Revision	Date
0	Initial Issue	1/28/10

TABLE OF CONTENTS

1.0 PURPOSE

This technical report identifies the methodology used in the aging management evaluation of the Diablo Canyon Power Plant (DCPP). This report provides a detailed evaluation of all electrical cables, plant environmental data, fuses/fuse blocks, terminal blocks, metal enclosed bus, non-EQ electrical containment penetrations, cable tie wraps, switchyard insulators, conductors, and connections.

2.0 SCOPE

This technical report covers all DCPP cables, fuse/fuse blocks, terminal blocks, splices, fuses not located in active components, metal enclosed bus, electrical containment penetrations, tie wraps, insulators, and switchyard and transmission conductors, and connections.

3.0 CABLES AND CONNECTIONS

3.1 Methodology

The spaces approach is used to evaluate cable at DCPP. All cable types installed at DCPP were identified for insulating material. The insulating material is then compared to the existing plant environment. The limiting condition of cable service life was used to establish the parameters for adverse localized environments. A review of circuits was performed to determine which are high voltage, low level instrumentation cables. A separate review determined which medium voltage cables are subject to moisture intrusion and perform an intended function.

3.2 Cables, Terminal Blocks, and Penetrations Purchased EQ

DCPP purchased selected cable, terminal blocks, and penetrations as environmentally qualified. The EQ reports for these cables are listed below:

- EQ File EH01, GE Electrical Penetration
- EQ File EH02, Okonite EPR/Hypalon Cables
- EQ File EH03, Raychem Flamtrol XLPE Insulated Cable
- EQ File EH04, Rockbestos Firewall Cables
- EQ File EH05, BIW Silicone Cables
- EQ File EH06, Okonite Okozel Cables
- EQ File EH08, Continental Signal & Thermocouple Cables
- EQ File EH09, BIW Fan Cooler Cables
- EQ File EH10, Raychem Stilan Cable
- EQ File EH11, Raychem Cable Splice Assemblies
- EQ File EH16, Okonite 5 kV EPR (Okoguard) Insulated Cable
- EQ File EH21, Okonite X-Olene/FMR Cables
- EQ File EH22, General Phenolic Terminal Blocks
- EQ File EH23, BIW Coaxial Cable & 10/C Cable Assembly
- EQ File EH25B, Whittaker & Combustion Engineering/Westinghouse Incore Thermocouple Connector Assembly

- EQ File EH27, Whittaker – ERD Electrical Connectors & Mineral Insulated Cable
- EQ File EH35, Incore Tefzel Cables
- EQ File EH37, CONAX Electrical Penetrations
- EQ File IH52A, Conax Nuclear Service Connector
- EQ File IH54, EGS Grayboot Connector
- EQ File IH55, EGS Bayonet Connectors

3.3 Plant Normal Environmental Data

3.3.1 Radiological Conditions

DCPP is organized into five radiation zones (0 to 4) as defined in DCM T-20, Appendix A. Figures in Appendix A identify the specific plant spaces to which each zone applies. The values given in DCM T-20 Appendix A, 4.3.2 are for 40 year integrated rad dose. In the following list and table, the values provided are multiplied by 1.5 to derive a 60 year integrated rad dose. The first four zones are:

- Zone 0 – 2.6 x 10^2 rad
- Zone 1 – 5.3 x 10^2 rad
- Zone 2 – 1.3 x 10^3 rad
- Zone 3 – 7.9 x 10^3 rad

Table 3.3.1 provides the zone 4 radiological data for each Zone 4 area as defined in DCM T-20, Appendix A Table A4.3-2.

Table 3.3.1 Zone 4 Radiological Environment

Building/Room	60 Year Normal Rad Dose	Comments
Liquid Holdup Tank	1.2 x 10^5 rad	
LHUT Recirc Pump Room	2.7 x 10^4 rad	
Liquid Radwaste Filters	1.0 x 10^6 rad	
Radwaste Drain Tank Room	2.0 x 10^5 rad	
Gas Decay Tanks	3.6 x 10^8 rad	
RHR Pump Compartments	2.3 x 10^5 rad	
Waste Gas Compressor Comp.	1.8 x 10^7 rad	
RHR Hx Compartment	2.7 x 10^5 rad	
Charging Pump Compartment	1.8 x 10^6 rad	
Letdown Hx Compartment	7.4 x 10^5 rad	
Radwaste Concentrator Comp.	1.8 x 10^4 rad	
Boric Acid Evaporator	4.2 x 10^6 rad	
LHUT Letdown lines close to piping in ceiling	5.3 x 10^4 rad	
CVCS Filters	5.3 x 10^6 rad	
Volume Control Tank	1.5 x 10^7 rad	
CVCS Demineralizers Comp.	6.3 x 10^8 rad	

Table 3.3.1 Zone 4 Radiological Environment		
Building/Room	**60 Year Normal Rad Dose**	**Comments**
CVCS Demineralizers Pipe Pen.	5.1×10^5 rad	
Spent Resin Tank Comp.	1.7×10^8 rad	
Spent Resin Tank Valve Gallery	4.8×10^5 rad	
Waste Concentrates Holding Tank	2.0×10^4 rad	
Concentrates Holding Tank	2.6×10^5 rad	
Drumming Station (behind shield)	9.5×10^4 rad	
Boric Acid Tanks	5.0×10^4 rad	
Ion Exchanger Compartment	1.1×10^8 rad	
Ion Exchanger Valve Gallery	3.0×10^5 rad	

Note: values are conservatively based on maximum dose rate

DCM T-20, Appendix A, 4.3.1 provides radiation data inside containment. The normal integrated gamma radiation dose for 40-year design life is 1×10^7 rads. Applying a factor of 1.5 for a 60-year life arrives at 1.5×10^7 rads.

3.3.2 Temperature Environment

DCPP normal operating temperatures are defined in DCM T-20, Appendix A, Table A4.2-1. For ease of reference the maximum temperatures in each area of the plant are shown in Table 3.3.2.

Table 3.3.2 Temperature Environment		
Area/Room	**Max Average Temperature (°F)**	**Comments**
Inside Containment		
General open areas	120	
CRDM shroud area	150	
Inside primary concrete shield	135	
Auxiliary Building		
Control Room	85	
Control Room HVAC Mech Equip Rm	104	
480V SWGR, inverters, battery & cable spreading rooms	104	
Areas GE & GW	104	
Areas H & K		
Boron Injection Tank Room	140	
Liquid Holdup Tank Rooms	130	
All other areas	104	
Areas J & L	104	
Turbine Building		
Open space Areas A (above 140’), B, C, D, E	129	

Table 3.3.2 Temperature Environment		
Area/Room	**Max Average Temperature (°F)**	**Comments**
4KV SWGR & cable spreading rooms	104	
12KV SWGR rooms	104	
Diesel Generator Rooms	107	
El 140’ near pressurization fans	117	
All Outdoor Areas	91	

3.3.3 Wind environment

DCPP UFSAR 2.3 describes the wind conditions at DCPP. The prevailing wind direction is from the northwest with an average annual wind speed about 10 mph. The maximum recorded hourly mean wind speed is 54 mph, with a highest recorded peak gust at 84 mph.

Moderate to strong sea breezes are common in the afternoon hours of May through September while, at night, weak offshore drainage winds are prevalent.

3.3.4 Ultraviolet Radiation

SAND96-0344 paragraph 4.1.4 describes the aging effects associated with ultraviolet radiation. The source of UV radiation in nuclear power plants is described as sunlight or ultraviolet or fluorescent lamps.

3.4 Cable Insulation Evaluation

DCPP UFSAR Appendix 8.3B provides a summary of the cable insulation types used at Diablo Canyon, as follows:

- Power cables for 4.16 kV and 12 kV service are single conductor with ethylene-propylene (EPR) insulation.
- Low-voltage power cables expected to operate in ambient temperatures of 40 to 50°C (104 – 122°F) have ethylene-propylene insulation (EPR) with smaller cables insulated with cross-linked polyethylene (XLPE).
- Low-voltage power cables located very near or connected to hot equipment and devices, or those required to operate in containment during a LOCA are insulated with silicone rubber, XLPE, Tefzel, or equivalent.
- Cables for containment fan cooler motors are insulated with a combination of silicone resin-impregnated glass braid, polymide (Kapton) tapes, and an asbestos mat (see EQ File EH-09 for EQ cables).
- Cables for pressurizer heaters are insulated with a combination of mica and glass tapes.

- Cables for control circuits operating in average maximum ambient temperatures are insulated with cross-linked polyethylene (XLPE).
- Cables for control circuits located very near or connected to hot equipment and devices, or required to operate in containment during a LOCA, are insulated with silicone rubber, XLPE, Tefzel, or equivalent insulation.
- Instrument cables operating in a normal environment are insulated with cross-linked polyethylene (XLPE).
- Instrument cables located very near or connected to hot equipment and devices, or required to operate in containment during a LOCA, are insulated with silicone rubber.
- Coax and triax cables are insulated with alkane-imide polymer and cross-linked polyolefin [XLPO].
- Incore thermocouple extension wire primary insulation is a heavy polyimide enamel. [NOTE all incore thermocouple extension cable is EQ]

Drawing 032443 provides the specification for telephone cable at DCPP, indicating all telephone cables are PVC.

Radio antenna circuits at Diablo Canyon are installed with coaxial cable using polyethylene insulation, an example is shown on drawing 469992.

3.5 Cable Insulation 60-Year Service-Limiting Environment

Table 3.5 provides the 60-year service-limiting environments for the insulation types that require aging management at DCPP. Unless noted, the 60-year service-limiting environments are from EPRI-TR1013475 Table 10-1.

Table 3.5 Cable Insulation 60-Year Service-Limiting Environment

Insulation Type	60-Year Service Environment		Comment
	Temperature	Radiation Dose	
Alkane-imide Polymer	188°F	1×10^8 rads	See Note 1
Cross-linked Polyethylene (XLPE)	188°F	1×10^8 rads	
Cross-linked Polyolefin (XLPO)	181°F	1×10^8 rads	See Note 2
Ethylene Propylene Rubber (EPR)	167°F	5×10^7 rads	
Polyethylene (PE)	112°F	2×10^7 rads	See Note 3
Polyvinyl Chloride (PVC)	112°F	2×10^7 rads	
Silicone Rubber (SR)	273°F	3×10^6 rads	
Tefzel	228°F	3×10^7 rads	

NOTES:

1. NUREG/CR-6384, Vol 1, Table 3.2 identifies Alkane-imide as a component of Raychem Flamtrol cable and identifies the cable insulation type as XLPE (p. xxiii). Therefore, the values of XLPE are used.
2. SAND96-0344 Table 4-2 specifies the temperature rating for XLPO instrument cable. SAND 96-0344 Table 4-7 indicates threshold radiation ranges for XLPE and XLPO are the same, therefore XLPO is assumed to have the same 60-Year Service Radiation Dose as XLPE.
3. Coaxial antenna cable insulating material is assumed to be a foam polyethylene based on Andrews Product Specifications for Heliax® /Radiax®.

3.6 Cable Insulation Evaluation

The following is an evaluation of each of the insulation types that require aging management to determine if the cable insulation materials will perform their license renewal intended function for the extended period of operation.

3.6.1 Alkane-imide Polymer

Alkane-imide Polymer has a 60-year service-limiting temperature of 188°F and a 60-year service-limiting radiation dose of 1 x 10^8 rads.

The cables that use Alkane-imide Polymer insulation are coax and triax instrumentation cables.

The DCPP temperature environments in all areas are less severe than the 60-year service-limiting temperature of Alkane-imide Polymer.

The following locations exceed the service-limiting radiation dose of 1 x 10^8 rads. An engineering review indicates no alkane-imide polymer cable is routed in these areas.

- Gas Decay Tanks
- CVCS Demineralizers Compartment
- Spent Resin Tank Compartment
- Ion Exchanger Compartment

The cables with Alkane-imide Polymer insulation in all areas of DCPP will perform their intended function for the period of extended operation.

3.6.2 Cross-Linked Polyethylene (XLPE)

XLPE insulation has a 60-year service-limiting temperature of 188°F and a 60-year service-limiting radiation dose of 1 x 10^8 rads.

The cables that use XLPE insulation are power cables, control cables, or instrument cables. In power cable ohmic heating adds to the cable's ambient temperature. EPRI 1013475, Chapter 12 states the maximum temperature increase caused by ohmic heating in power cable applications at 40°C ambient will be 32°C. The maximum cable insulation temperature will be 72°C (162°F) which is less than the 60-year service-limiting temperature of 188°F.

The DCPP temperature environments in all areas are less severe than the 60-year service-limiting temperature of XLPE.

The following locations exceed the service-limiting radiation dose of 1×10^8 rads. An engineering review indicates no Cross-Linked Polyethylene cable is routed in these areas.

- Gas Decay Tanks
- CVCS Demineralizers Compartment
- Spent Resin Tank Compartment
- Ion Exchanger Compartment

The cables with XLPE insulation in all areas of DCPP will perform their intended function for the period of extended operation.

3.6.3 Cross-Linked Polyolefin (XLPO)

XLPO insulation has a 60-year service-limiting temperature of 181°F and a 60-year service-limiting radiation dose of 1×10^8 rads.

The cables that use XLPO insulation are coax and triax instrumentation cables.

The DCPP temperature environments in all areas are less severe than the 60-year service-limiting temperature of XLPO.

The following locations exceed the service-limiting radiation dose of 1×10^8 rads. An engineering review indicates no Cross-Linked Polyolefin cable is routed in these areas.

- Gas Decay Tanks
- CVCS Demineralizers Compartment
- Spent Resin Tank Compartment
- Ion Exchanger Compartment

The cables with XLPO insulation in all areas of DCPP will perform their intended function for the period of extended operation.

3.6.4 Ethylene Propylene Rubber (EPR)

EPR insulation has a 60-year service-limiting temperature of 167°F and a 60-year service-limiting radiation dose of 5×10^7 rads.

The cables that use EPR insulation are power cables. In power cable, ohmic heating adds to the cable's ambient temperature. EPRI 1013475, Chapter 12 states the maximum temperature increase caused by ohmic heating in power cable applications at 40°C ambient will be 32°C. The maximum cable insulation temperature will be 72°C (162°F) which is less than the 60-year service-limiting temperature of 167°F.

The DCPP temperature environments in all areas are less severe than the 60-year service-limiting temperature of EPR.

The following locations exceed the service-limiting radiation dose of 5×10^7 rads. An engineering review indicates no Ethylene Propylene Rubber cable is routed in these areas.

- Gas Decay Tanks
- CVCS Demineralizers Compartment
- Spent Resin Tank Compartment
- Ion Exchanger Compartment

The cables with EPR insulation in all areas of DCPP will perform their intended function for the period of extended operation.

3.6.5 Polyethylene (PE)

Polyethylene insulation has a 60-year service-limiting temperature of 112°F and a 60-year service-limiting radiation dose of 2×10^7 rads.

The cables that use polyethylene foam are the Heliax® cables for the plant radio system.

Table 3.3.2 shows that many areas of Diablo Canyon exceed the 60-year service-limiting temperatures for PE.

The following locations exceed the service-limiting radiation dose of 2×10^7 rads. An engineering review indicates no Polyethylene cable is routed in these areas.

- Gas Decay Tanks
- CVCS Demineralizers Compartment
- Spent Resin Tank Compartment
- Ion Exchanger Compartment

Some areas of DCPP exceed the 60 year service limiting temperature for PE insulation and will be considered a potential adverse localized environment.

3.6.6 Polyvinyl Chloride (PVC)

Polyvinyl Chloride insulation has a 60-year service-limiting temperature of 112°F and a 60-year service-limiting radiation dose of 2×10^7 rads.

The cables that use polyvinyl chloride are the communication cables for the plant telephone system.

Table 3.3.2 shows that many areas of Diablo Canyon exceed the 60-year service-limiting temperatures for PVC.

The following locations exceed the service-limiting radiation dose of 2×10^7 rads. An engineering review indicates no Polyvinyl Chloride cable is routed in these areas.

- Gas Decay Tanks
- CVCS Demineralizers Compartment
- Spent Resin Tank Compartment
- Ion Exchanger Compartment

Some areas of DCPP exceed the 60 year service limiting temperature for PVC insulation and will be considered a potential adverse localized environment.

3.6.7 Silicone Rubber (SR)

SR insulation has a 60-year service-limiting temperature of 273°F and a 60-year service-limiting radiation dose of 3×10^6 rads.

The cables that use SR insulation are power, control, or instrumentation cables. In power cable ohmic heating adds to the cable's ambient temperature. EPRI 1013475, Chapter 12 states the maximum temperature increase caused by ohmic heating in power cable applications at 40°C ambient will be 32°C. The maximum cable insulation temperature will be 72°C (162°F) which is less than the 60-year service-limiting temperature of 273°F.

The DCPP temperature environments in all areas are less severe than the 60-year service-limiting temperature of SR.

The following locations exceed the service-limiting radiation dose of 3×10^6 rads:

- Gas Decay Tanks
- Waste Gas Compressor Compartment
- CVCS Demineralizers Compartment
- Spent Resin Tank Compartment
- Ion Exchanger Compartment
- Boric Acid Evaporator

An engineering review indicates no Silicone Rubber cable is routed in the first five areas noted above. The cables with SR insulation in all other areas of DCPP will perform their intended function for the period of extended operation.

Engineering documentation will be reviewed to determine if SR cables are routed through the Boric Acid Evaporator room and, if found, existing cable will be inspected for radiation related degradation.

3.6.8 Tefzel (TEFZ)

TEFZ insulation has a 60-year service-limiting temperature of 228°F and a 60-year service-limiting radiation dose of 3×10^7 rads.

The cables that use TEFZ insulation are low voltage power or control cables.

The DCPP temperature environments in all areas are less severe than the 60-year service-limiting temperature of TEFZ.

The following locations exceed the service-limiting radiation dose of 3×10^7 rads. An engineering review indicates no Tefzel cable is routed in these areas.

- Gas Decay Tanks
- CVCS Demineralizers Compartment
- Spent Resin Tank Compartment
- Ion Exchanger Compartment

The cables with TEFZ insulation in all areas of DCPP will perform their intended function for the period of extended operation.

3.7 Non-EQ Electrical Penetration Connections

DCPP has no non-EQ electrical containment penetrations that require aging management (LRFS-08-165).

3.8 Fuse Holders

3.8.1 Fuse Holder 60-year Service Limiting Conditions

The insulating material for fuse holders at DCPP is assumed to be phenolic resin material. EPRI TR1013475, Table 10-1 provides the 60-year service limiting environment for phenolic resin as:

- Temperature 231°F
- Radiation 4×10^7 rads

3.8.2 Fuse Holder Insulation Evaluation

The DCPP temperature environments in all areas are less severe than the 60-year service-limiting temperature of phenolic resin material.

The following locations exceed the service-limiting radiation dose of 4×10^7 rads. An engineering review indicates there are no fuse boxes in these areas.

- Gas Decay Tanks
- CVCS Demineralizers Compartment
- Spent Resin Tank Compartment
- Ion Exchanger Compartment

Degradation of organic fuse holder insulating material caused by chemical agents is not an aging effect that requires management at DCPP. All fuse holders are located within metal enclosures and are not subject to any type of chemical agents except borated water leakage which is managed using the Boric Acid aging management program.

Moisture that causes loss of insulating properties is not an aging effect that requires management at DCPP. All non-EQ fuse holders are located within metal enclosures and are not subject to any type of moisture. The fuse holders are designed to function with 100% relative humidity.

Contamination by foreign material that causes the formation of electrical tracking is not an aging effect that requires management at DCPP. All non-EQ fuse holders are located within metal enclosures and are not subject to any type of contamination by foreign material such as dirt and dust.

Fuse holders in all areas of DCPP will perform their intended function for the period of extended operation.

3.9 Terminal Blocks

3.9.1 Terminal Block 60-year Service Limiting Conditions

The insulating material for fuse holders at DCPP is assumed to be phenolic resin material. EPRI TR1013475, Table 10-1 provides the 60-year service limiting environment for phenolic resin as:

- Temperature 231°F
- Radiation 4×10^7 rads

3.9.2 Terminal Block Insulation Evaluation

The DCPP temperature environments in all areas are less severe than the 60-year service-limiting temperature of phenolic resin material.

The following locations exceed the service-limiting radiation dose of 4×10^7 rads. An engineering review indicates there are no terminal boxes in these areas.

- Gas Decay Tanks
- CVCS Demineralizers Compartment
- Spent Resin Tank Compartment
- Ion Exchanger Compartment

Degradation of organic terminal block insulating material caused by chemical agents is not an aging effect that requires management at DCPP. All terminal blocks are located within metal enclosures and are not subject to any type of chemical agents except borated water leakage which is managed using the Boric Acid aging management program.

Moisture that causes loss of insulating properties is not an aging effect that requires management at DCPP. All non-EQ terminal blocks are located within metal enclosures and are not subject to any type of moisture. The terminal blocks are designed to function with 100% relative humidity.

Contamination by foreign material that causes the formation of electrical tracking is not an aging effect that requires management at DCPP. All non-EQ terminal blocks are located within metal enclosures and are not subject to any type of contamination by foreign material such as dirt and dust.

Terminal blocks with phenolic insulation in all areas of DCPP will perform their intended function for the period of extended operation.

3.10 Adverse Localized Environment

In most areas within DCPP, the actual ambient environment (i.e., temperature, radiation) is less severe than DCPP design environment. However, in a limited number of localized areas, the actual environment may be more severe than design environment. Conductor insulation materials used in cables and connections degrade more rapidly in adverse localized environments.

An adverse localized environment is significantly more severe than the specified service environment for the cable and connections. A plant walk down will be required to identify adverse localized environments. At DCPP adverse localized environments are defined as follows:

- Temperature within 3 feet of cable or raceway is greater than 112°F for PVC or Heliax®/Radiax® cable, 167°F for all other cables and splices. This is based on the EPR temperature for all cables and splices except PVC/Heliax® which are rated at the lower temperature.
- 231°F for fuse and terminal boxes. This temperature is based on the 60-year service temperature of phenolic material.
- Radiation (neutron) dose for the area is greater than 3 x 10^6 rads. This is a conservative value based on SR insulation having a 60-year normal radiation dose of 3 x 10^6 rads.
- Radiation (ultraviolet) aging effects may be evident where cable is exposed to sunlight or within three feet of fluorescent lighting without a protective cover.
- Moisture is indicative of an adverse localized environment if the cable is subject to significant moisture. Significant moisture is defined as periodic exposures that last for more than a few days.

In those areas where it can be conclusively determined there are no PVC communication cables or Heliax radio cables, the temperature and radiation environments may be raised to 167°F (based on EPR) and 4 x 10^7 rads (based on phenolic material) respectively.

3.11 Cables Used in Instrumentation Circuits Sensitive to Reduction in IR

3.11.1 Table 3.11.1 identifies the instrumentation circuits at DCPP which contain sensitive, high voltage, low level signal circuits (Ref DCPP letters LRFS-08-162, 08-164, 08-166, and 08-180). The results of the circuit reviews are identified in the comment column.

Table 3.11.1 – Instrumentation Circuits Sensitive to Reduction in IR

Comp No	Circuit	Description	LR	Comments

Table 3.11.1 – Instrumentation Circuits Sensitive to Reduction in IR				
Comp No	**Circuit**	**Description**	**LR**	**Comments**
NE-31 NE-32	NE-31 NE-32	Source Range Detector	Y	Note 1
NE-35 NE-36	NE-35 NE-36	Intermediate Range Detectors	Y	Note 1
NE-41A/B NE-42A/B NE-43A/B NE-44A/B	NE-41A/B NE-42A/B NE-43A/B NE-44A/B	Power Range Detectors	Y	Note 1
NE-51 NE-52	NE-51 NE-52	Post Accident Neutron Flux Monitors	Y	Note 2
RE-1	R-01	Control Room Area Monitoring Channel	N	Note 3
RE-2	R-02	Containment Area Monitoring Channel	N	Note 3
RE-3	R-03	Oily Water Separator Effluent Monitoring Channel	N	Note 3
RE-4	R-04	Centrifugal Charging Pump CCP3 (Room Area) Monitoring Channel	N	Note 3
RE-6	R-06	NSSS Sampling Room Area Monitoring Channel	N	Note 3
RE-7	R-07	In-Core Seal Table Area Monitoring Channel	N	Note 3
RE-10	R-10	Auxiliary Control Board Area Monitoring Channel.	N	Note 3
RE-11	R-11	Containment Air Particulate Monitoring Channel	N	Note 3
RE-12	R-12	Containment Air Radioactive Gas Monitoring Channel	N	Note 3
RE-13	R-13	RHR Exhaust Duct Air Particulate Monitoring Channel	N	Note 3
RE-14 RE-14R	R-14 R-14R	Plant Vent Noble Gas Radioactivity Monitoring Channels	N	Note 3
RE-15 RE-15R	R-15 R-15R	Condenser Air Ejector Discharge Radioactivity Gas Discharge Monitoring Channels	N	Note 3

Table 3.11.1 – Instrumentation Circuits Sensitive to Reduction in IR

Comp No	Circuit	Description	LR	Comments
RE-17A RE-17B	R-17A R-17B	Component Cooling Header Discharge Water Effluent Monitoring Channels	N	Note 3
RE-18 RE-18-1	R-18	Liquid Radwaste Discharge Line Effluent Monitoring Channel	N	Note 3
RE-19	R-19	Steam Generator Blowdown Sample Effluent Monitoring Channel	N	Note 3
RE-22	R-22	Gas Decay Tank Radioactive Gas Discharge Monitoring Channel	N	Note 3
RE-23	R-23	Steam Generator Blowdown Tank Liquid Discharge Effluent Monitoring Channel	N	Note 3
RE-24 RE-24R	R-24 R-24R	Plant Vent Iodine Monitoring Channels	N	Note 3
RE-25 RE-26	R-25 R-26	Control Room Air Intake Monitoring Channels	Y	Note 4
RE-28 RE-28R	R-28 R-28R	Plant Vent Particulate Radioactivity Monitoring Channels	N	Note 3
RE-29	R-29	Plant Vent High Radiation Gross Gamma Monitoring Channel	N	Note 3
RE-30 RE-31	R-30 R-31	Containment High Range Area Radiation Monitoring Channels	Y	Note 2
RE-34	R-34	Plant Vent ALARA Monitoring Channel	N	Note 3
RE-41 RE-42 RE-43	R-41 R-42 R-43	Gas Decay Tank Cubicle Radiation Monitoring Channels	N	Note 3
RE-44A RE-44B	RE-44A RE-44B	Containment Exhaust Radiation Monitoring Channels	Y	Note 1
RE-48	R-48	Post Accident Sampling Room Area Monitoring Channel	N	Note 3
RE-51 RE-52 RE-53 RE-54	R-51 R-52 R-53 R-54	Control Room Pressurization System Ventilation Air Intake Air Monitoring Channels	Y	Note 1
RE-58	R-58	Spent Fuel Pool Area Monitoring Channel	Y	Note 1

Table 3.11.1 – Instrumentation Circuits Sensitive to Reduction in IR				
Comp No	**Circuit**	**Description**	**LR**	**Comments**
RE-59	R-59	New Fuel Storage Area Monitoring Channel	Y	Note 1
RE-60	R-60	TSC Office Area Radiation Monitoring Channel	N	Note 3
RE-61	R-61	TSC Operations/RMS Area Monitoring Channel	N	Note 3
RE-62	R-62	TSC Computations Center Area Monitoring Channel	N	Note 3
RE-63	R-63	TSC NRC Office Area Monitoring Channel	N	Note 3
RE-64	R-64	TSC HVAC Equipment Room Area Monitoring Channel	N	Note 3
RE-65	R-65	TSC Laboratory Area Monitoring Channel	N	Note 3
RE-66	R-66	TSC Air Particulate Monitoring Channel	N	Note 3
RE-67	R-67	TSC Noble Gas Monitoring Channel	N	Note 3
RE-68	R-68	TSC Laboratory Air Particulate Monitoring Channel	N	Note 3
RE-69	R-69	TSC Laboratory Noble Gas Monitoring Channel	N	Note 3
RE-71 RE-72 RE-73 RE-74	R-71 R-72 R-73 R-74	Main Steam Line Radiation Monitoring Channels	N	Note 3
RE-82	R-82	TSC Iodine Monitoring Channel	N	Note 3
RE-83	R-83	TSC Laboratory Iodine Monitoring Channel	N	Note 3
RE-84	R-84	Contact Inspection Station Radiation Monitoring Channel	N	Note 3
RE-85	R-85	One Meter Inspection Station Radiation Monitoring Channel	N	Note 3
RE-87	R-87	Plant Vent Extended Range Monitoring Channels	N	Note 3
RE-90	R-90	Radwaste Storage Area Radiation Monitoring Channel	N	Note 3
RE-92	R-92	Laundry Processing Room Radiation Monitoring Channel	N	Note 3

Table 3.11.1 – Instrumentation Circuits Sensitive to Reduction in IR				
Comp No	**Circuit**	**Description**	**LR**	**Comments**
RF-87A RF-87B	RF-87A RF-87B	Plant Vent Extended Range Sampler Assemblies	N	Note 3
RX-55	RX-55	Laundry and Radwaste Facility Exhaust Sampler	N	Note 3
RX-56	RX-56	Radwaste Storage and Laundry Facility Exhaust Sampler	N	Note 3

NOTES
1. Managed by XI.E2 (Ref. LRFS-08-164)
2. Managed by X.E1 EQ program (Ref. EZ-002)
3. Aging Management not required, instrument not in scope
4. No high voltage cable (Ref. LRFS-08-166)

3.11.2 In-Scope Instrumentation Circuits, Cables and Calibrations

Table 3.11.2 is a list of the in-scope instrumentation circuits. The high voltage cable IDs, Drawing, and Procedure References are shown.

3.11.2 In-scope Instrumentation Circuits					
Circuit	**Description**	**Cable ID(s)**	**Drawing Reference, U1**	**Drawing Reference, U2**	**Procedure**
NE-31	Source Range Detectors	RNIA13, 13C RNIA14	437888, 437940, 437974, 502127	441465, 452742, 452734	TS1.DC1
NE-32		RNIB13, 13C RNIB14	437888, 437940, 497975, 502127	441465, 452742, 452744	
NE-35	Intermediate Range Detectors	RNIA08, 8C RNIA09, 9C	437888, 437940 437974, 448917	441465, 452742, 452743	TS1.DC1
NE-36		RNIB08, 8C RNIB09, 9C	437888, 437940 437975, 448917	441465, 452742, 452744	TS1.DC1
NE-41A/B	Power Range Detectors	RNIA01, 1C RNIA02, 2C RNIA03, 3C	437888, 437940 437974, 448917	441465, 452742, 452743	TS1.DC1

3.11.2 In-scope Instrumentation Circuits					
Circuit	**Description**	**Cable ID(s)**	**Drawing Reference, U1**	**Drawing Reference, U2**	**Procedure**
NE-42A/B		RNIB01, 1C RNIB02, 2C RNIB03, 3C	437888, 437940 437975, 448917	441465, 452742, 452744	TS1.DC1
NE-43A/B		RNIC01, 1C RNIC02, 2C RNIC03, 3C	437888, 437940 437976, 448917	441465, 452742, 452745	TS1.DC1
NE-44A/B		RNID01, 1C RNID02, 2C RNID03, 3C RNIOD12 RNIOD13 RNIOD14	437888, 437940 437977, 448917	441465, 452742, 452746	TS1.DC1
R-44A R-44B	Contain-ment Exhaust Channels	I0044RM1A I0044RM1B I0044RM3A I0044RM3B	521663, 6011481-28, 6011481-61	521671, 6011481-28, 6011481-61	STP I-39-R44A.B STP I-39-R44B.B
R-51 R-52 R-53 R-54	Control Room Pressuriza-tion Channels	MV526Y MV626Y MV526Z MV626Z	447528, 501163 501164	447528, 501170, 501171	STP I-118B2
R-58	Spent Fuel Pool Area Monitoring Channel	MV265 MV267	488918, 501709	435796, 502660	STP I-119B3
R-59	New Fuel Storage Area Moni-toring Channel	MV266 MV268			

3.12 In-Scope Medium Voltage Cable

Medium voltage cables at DCPP were reviewed to determine which are installed in conduit that are subject to moisture and have operating durations of greater than twenty-five percent of the time.

3.12.1 Evaluation of Medium Voltage Cable

Table 3.12.1 provides a listing of all medium voltage cables with a determination of which are within the scope of License Renewal that are potentially managed by AMP XI.E3. A review of cable routing then identifies the AMP which will manage the aging of in-scope cables.

Table 3.12.1 Medium Voltage Cable Evaluation

Cable ID	Volt Class	Unit	From EID	To EID	LR	AMP	Comment
HWH-1	4.16kV	1	SHE7	500kV SY	N	NA	Note 2
HWH-3	4.16kV	1	SHD11	230kV SY	N	NA	Note 2
Various	12kV	1	SVU15	12kV Undrgrnd	N	NA	Note 2
D05V00A	12kV	1	SVD5	BPO15	N	NA	Note 2
D05V00A1	12kV	1	BPO15	CWP1	N	NA	Note 2
D05V00B	12kV	1	SVD5	BPO15	N	NA	Note 2
D05V00B1	12kV	1	BPO15	CWP1	N	NA	Note 2
D06H00	4.16kV	1	SHD6	SP5D	N	NA	Note 2
D06RV00	12kV	1	SVD6	SVD6R	N	NA	Note 2
D06V00	12kV	1	SVD6R	BTF43E	N	NA	Note 2
D06V00A	12kV	1	BTX43E	RCP4	N	NA	Note 2
D07H00	4.16kV	1	SHD7	CVP1	N	NA	Note 2
D07RV00	12kV	1	SVD7	SVD7R	N	NA	Note 2
D07V00	12kV	1	SVD7R	BTF44E	N	NA	Note 2
D07V00A	12kV	1	BTX44E	RCP2	N	NA	Note 2
D08H00	4.16kV	1	SHD8	BPO18	N	NA	Note 2
D08H00A	4.16kV	1	BPO18	SP4D	N	NA	Note 2
D09H0A	4.16kV	1	SHD9	CP1	N	NA	Note 2
D09H0B	4.16kV	1	SHD9	CBP1	N	NA	Note 2
D10H00	4.16kV	1	SHD10	SP1D	N	NA	Note 2
D12H00	4.16kV	1	SHD12	SP2D	N	NA	Note 2
D13H00	4.16kV	1	SHD13	SP3D	N	NA	Note 2
E03RV00	12kV	1	SVE3	SVE3R	N	NA	Note 2
E03V00	12kV	1	SVE3R	BTF41E	N	NA	Note 2
E03V00A	12kV	1	BTX41E	RCP1	N	NA	Note 2
E04H00	4.16kV	1	SHE4	SP3E	N	NA	Note 2
E04RV00	12kV	1	SVE4	SVE4R	N	NA	Note 2
E04V00	12kV	1	SVE4R	BTF40E	N	NA	Note 2
E04V00A	12kV	1	BTX40E	RCP3	N	NA	Note 2
E05H00	4.16kV	1	SHE5	SP2E	N	NA	Note 2
E05V00A	12Kv	1	SVE5	BPO17	N	NA	Note 2
E05V00A1	12kV	1	BPO17	CWP2	N	NA	Note 2
E05V00B	12kV	1	SVE5	BPO17	N	NA	Note 2
E05V00B1	12kV	1	BPO17	CWP2	N	NA	Note 2
E06H00	4.16kV	1	SHE6	H2DP1	N	NA	Note 2
E08H00	4.16kV	1	SHE8	SP1E	N	NA	Note 2
E09H00A	4.16kV	1	SHE9	CP3	N	NA	Note 2
E09H00B	4.16kV	1	SHE9	CBP3	N	NA	Note 2

Table 3.12.1 Medium Voltage Cable Evaluation

Cable ID	Volt Class	Unit	From EID	To EID	LR	AMP	Comment
E10H00	4.16kV	1	SHE10	SP4E	N	NA	Note 2
E11H00A	4.16kV	1	SHE11	CP2	N	NA	Note 2
E11H00B	4.16kV	1	SHE11	CBP2	N	NA	Note 2
E12H00	4.16kV	1	SHE12	BPO20	N	NA	Note 2
E12H00A	4.16kV	1	BPO20	SP5E	N	NA	Note 2
F07H00A	4.16kV	1	SHF7	DEG3	Y	XI.E1	Note 1,4
F07H00B	4.16kV	1	SHF7	DEG3	Y	XI.E1	Note 1,4
F08H00	4.16kV	1	SHF8	BJA219	Y	XI.E1	Note 1
F08H00A	4.16kV	1	BJA219	MHF8	Y	XI.E3	
F09H00	4.16kV	1	SHF9	AFWP-3	Y	XI.E1	Note 4
F10H00	4.16kV	1	SHF10	SPF	Y	XI.E3	
F11H00	4.16kV	1	SHF11	CCP1	Y	XI.E1	Note 1,4
F12H00	4.16kV	1	SHF12	MHF12	Y	XI.E3	
F15H00	4.16kV	1	SHF15	SIP1	Y	XI.E1	Note 1,4
G05H00A	4.16kV	1	SHG5	DEG2	Y	XI.E1	Note 1,4
G05H00B	4.16kV	1	SHG5	DEG2	Y	XI.E1	Note 1,4
G06H00	4.16kV	1	SHG6	BJA216	Y	XI.E1	Note 1
G06H00A	4.16kV	1	BJA216	MHG6	Y	XI.E3	
G07H00	4.16kV	1	SHG7	CSP1	Y	XI.E1	Note 4
G08H00	4.16kV	1	SHG8	RHRP1	Y	XI.E1	Note 1,4
G09H00	4.16kV	1	SHG9	CCP2	Y	XI.E1	Note 1,4
G10H00	4.16kV	1	SHG10	SPG	Y	XI.E3	
G11H00	4.16kV	1	SHG11	CCP3	Y	XI.E1	Note 4
G12H00	4.16kV	1	SHG12	MHG12	Y	XI.E3	
H07H00A	4.16kV	1	SHH7	DEG1	Y	XI.E1	Note 1,4
H08H00	4.16kV	1	SHH8	AFWP-2	Y	XI.E1	Note 4
H09H00	4.16kV	1	SHH9	CSP2	Y	XI.E1	Note 4
H10H00	4.16kV	1	SHH10	SPH	Y	XI.E3	
H11H00	4.16kV	1	SHH11	RHRP2	Y	XI.E1	Note 1,4
H12H00	4.16kV	1	SHH12	MHH12	Y	XI.E3	
H15H00	4.16kV	1	SHH15	SIP2	Y	XI.E1	Note 1,4
Various	12kV	2	SVU21	SVD	N	NA	Note 2
Various	12kV	2	SVU22	SVE	N	NA	Note 2
TUV200A1 Z	12kV	2	SVU23	THU22	Y	XI.E3	
TUV200A2 Z	12kV	2	SVU23	THU22	Y	XI.E3	
TUV200A3 Z	12kV	2	SVU23	THU22	Y	XI.E3	
TUV200B1 Z	12kV	2	SVU23	THU22	Y	XI.E3	
TUV200B2 Z	12kV	2	SVU23	THU22	Y	XI.E3	
TUV200B3 Z	12kV	2	SVU23	THU22	Y	XI.E3	
TUV200C1 Z	12kV	2	SVU23	THU22	Y	XI.E3	
TUV200C2 Z	12kV	2	SVU23	THU22	Y	XI.E3	
TUV200C3 Z	12kV	2	SVU23	THU22	Y	XI.E3	
D03V00B	12kV	2	SVD3	SVD3R	N	NA	Note 2

Table 3.12.1 Medium Voltage Cable Evaluation

Cable ID	Volt Class	Unit	From EID	To EID	LR	AMP	Comment
D03V00	12kV	2	SVD3R	BTF44E	N	NA	Note 2
D03V00A	12kV	2	BTX44E	RCP2	N	NA	Note 2
D04V00C	12kV	2	SVD4	SVD4R	N	NA	Note 2
D04V00	12kV	2	SVD4R	BTF43E	N	NA	Note 2
D04V00A	12kV	2	BTX43E	RCP4	N	NA	Note 2
D05V00A	12kV	2	SVD5	CWP1	N	NA	Note 2
D05V00B	12kV	2	SVD5	CWP1	N	NA	Note 2
D06H00	4.16kV	2	SHD6	SP3D	N	NA	Note 2
D06V00A Z	12kV	2	SVD6	SVU21	N	NA	Note 2
D06V00B Z	12kV	2	SVD6	SVU21	N	NA	Note 2
D06V00C Z	12kV	2	SVD6	SVU21	N	NA	Note 2
D06V00D Z	12kV	2	SVD6	SVU21	N	NA	Note 2
D06V00E Z	12kV	2	SVD6	SVU21	N	NA	Note 2
D06V00F Z	12kV	2	SVD6	SVU21	N	NA	Note 2
D07H00	4.16kV	2	SHD7	SP2D	N	NA	Note 2
D09H00	4.16kV	2	SHD9	SP1D	N	NA	Note 2
D10H0A	4.16kV	2	SHD10	CP1	N	NA	Note 2
D10H0B	4.16kV	2	SHD10	CBP1	N	NA	Note 2
D11H00	4.16kV	2	SHD11	SP4D	N	NA	Note 2
D13H00	4.16kV	2	SHD13	SP5D	N	NA	Note 2
D20V00A	12kV	2	SVU20	BPO13	N	NA	Note 2
D20V00B	12kV	2	etc	12kV Undrgrnd	N	NA	Note 3
E04H00	4.16kV	2	SHE4	SP5E	N	NA	Note 2
E05H00A	4.16kV	2	SHE5	CP2	N	NA	Note 2
E05H00B	4.16kV	2	SHE5	CBP2	N	NA	Note 2
E05V00A	12kV	2	SVE5	CWP2	N	NA	Note 2
E05V00B	12kV	2	SVE5	CWP2	N	NA	Note 2
E06H00	4.16kV	2	SHE6	SP4E	N	NA	Note 2
E06V00C	12kV	2	SVE6	SVE6R	N	NA	Note 2
E06V00	12kV	2	SVE6R	BTF40E	N	NA	Note 2
E06V00A	12kV	2	BTX40E	RCP3	N	NA	Note 2
E07H00A	4.16kV	2	SHE7	CP3	N	NA	Note 2
E07H00B	4.16kV	2	SHE7	CBP3	N	NA	Note 2
E07V00B	12kV	2	SVE7	SVE7R	N	NA	Note 2
E07V00	12kV	2	SVE7R	BTF41E	N	NA	Note 2
E07V00A	12kV	2	BTX41E	RCP1	N	NA	Note 2
E08H00	4.16kV	2	SHE8	SP1E	N	NA	Note 2
E10H00	4.16kV	2	SHE10	H2DP1	N	NA	Note 2
E11H00	4.16kV	2	SHE11	SP2E	N	NA	Note 2
E12H00	4.16kV	2	SHE12	SP3E	N	NA	Note 2
F07H00A	4.16kV	2	SHF7	DEG3	Y	XI.E1	Note 1,4
F07H00B	4.16kV	2	SHF7	DEG3	Y	XI.E1	Note 1,4

Table 3.12.1 Medium Voltage Cable Evaluation							
Cable ID	**Volt Class**	**Unit**	**From EID**	**To EID**	**LR**	**AMP**	**Comment**
F08H00	4.16kV	2	SHF8	BJA218	Y	XI.E1	Note 1
F08H00A	4.16kV	2	BJA218	MHF8	Y	XI.E3	
F09H00	4.16kV	2	SHF9	AFWP-3	Y	XI.E1	Note 4
F10H00	4.16kV	2	SHF10	SPF	Y	XI.E3	
F11H00	4.16kV	2	SHF11	CCP1	Y	XI.E1	Note 1,4
F12H00	4.16kV	2	SHF12	MHF12	Y	XI.E3	
F15H00	4.16kV	2	SHF15	SIP1	Y	XI.E1	Note 1,4
G05H00A	4.16kV	2	SHG5	DEG1	Y	XI.E1	Note 1,4
G05H00B	4.16kV	2	SHG5	DEG1	Y	XI.E1	Note 1,4
G06H00	4.16kV	2	SHG6	BJA226	Y	XI.E1	Note 1
G06H00A	4.16kV	2	BJA226	MHG6	Y	XI.E3	
G07H00	4.16kV	2	SHG7	CSP1	Y	XI.E1	Note 4
G08H00	4.16kV	2	SHG8	RHRP1	Y	XI.E1	Note 1,4
G09H00	4.16kV	2	SHG9	CCP2	Y	XI.E1	Note 1,4
G10H00	4.16kV	2	SHG10	SPG	Y	XI.E3	
G11H00	4.16kV	2	SHG11	CCP3	Y	XI.E1	Note 1,4
G12H00	4.16kV	2	SHG12	MHG12	Y	XI.E3	
H07H00A	4.16kV	2	SHH7	DEG2	Y	XI.E1	Note 1,4
H08H00	4.16kV	2	SHH8	AFWP-2	Y	XI.E1	Note 4
H09H00	4.16kV	2	SHH9	CSP2	Y	XI.E1	Note 4
H10H00	4.16kV	2	SHH10	SPH	Y	XI.E3	
H11H00	4.16kV	2	SHH11	RHRP2	Y	XI.E1	Note 1,4
H12H00	4.16kV	2	SHH12	MHH12	Y	XI.E3	
H15H00	4.16kV	2	SHH15	SIP2	Y	XI.E1	Note 1,4

NOTES:
1. Routed above grade or indoors, not subject to moisture
2. No intended function, not in the scope of license renewal
3. No intended function, entire underground routing not shown
4. Energized < 25%

3.12.2 In-Scope Cables and Pullboxes

Table 3.12.2-1 provides a listing of all medium voltage cables within the scope of License Renewal, subject to significant moisture, and energized greater than twenty-five percent of the time.

Table 3.12.2-1 In-Scope Cables			
Cable ID	**Unit**	**From**	**To**
F08H00A	1	BJA219	ASP1
F10H00	1	SHF10	SPF
F12H00	1	SHF12	CCWP1
G06H00A	1	BJA216	ASP2
G10H00	1	SHG10	SPG

Table 3.12.2-1 In-Scope Cables

Cable ID	Unit	From	To
G12H00	1	SHG12	CCWP2
H10H00	1	SHH10	SPH
H12H00	1	SHH12	CCWP3
TUV200A1	2	SVU23	THU22
TUV200A2	2	SVU23	THU22
TUV200A3	2	SVU23	THU22
TUV200B1	2	SVU23	THU22
TUV200B2	2	SVU23	THU22
TUV200B3	2	SVU23	THU22
TUV200C1	2	SVU23	THU22
TUV200C2	2	SVU23	THU22
TUV200C3	2	SVU23	THU22
F08H00A	2	BJA218	ASP1
F10H00	2	SHF10	THF10
F12H00	2	SHF12	CCWP1
G06H00A	2	BJA226	ASP2
G10H00	2	SHG10	THG10
G12H00	2	SHG12	CCWP2
H10H00	2	SHH10	THH10
H12H00	2	SHH12	CCWP3

The table 3.12.2-2 provides a list of the pullboxes through which in-scope cable is routed. Each in-scope pullbox will be inspected for the presence of water at least once every two years. Those pullboxes in which water is found will have the water removed and the inspection frequency increased. This is adequate to identify insulation degradation due to moisture intrusion prior to failures of the insulation system.

Table 3.12.2-2 Pullboxes Containing In-scope Medium Voltage Cable

Unit	Pullbox	Cable ID	From	To	Dwg	Note
1	BPG4	F10H00 F12H00	SHF10 SHF12	SPF CCWP1	57597	2
1	BPG5	G10H00 G12H00	SGH10 SHG12	SPG CCWP2	57597	2
1	BPG6	H10H00 H12H00	SHH10 SHH12	SPH CCWP3	57597	2
1	BPO1	H10H00 H12H00	SHH10 SHH12	SPH CCWP3	57658	1
1	BPO4	G10H00 G12H00	SGH10 SHG12	SPG CCWP2	57658	1
1	BPO7	F10H00 F12H00	SHF10 SHF12	SPF CCWP1	57658	1

Table 3.12.2-2 Pullboxes Containing In-scope Medium Voltage Cable						
Unit	**Pullbox**	**Cable ID**	**From**	**To**	**Dwg**	**Note**
1	BPO13	TUV200A1 TUV200A2 TUV200A3 TUV200B1 TUV200B2 TUV200B3 TUV200C1 TUV200C2 TUV200C3	SVU23	THU22	57682	
1	BPO16	G06H00A	BJA216	ASP2	57682	
1	BPO19	F08H00A	BJA219	ASP1	57660 522196	
1	BPO25	TUV200A1 TUV200A2 TUV200A3 TUV200B1 TUV200B2 TUV200B3 TUV200C1 TUV200C2 TUV200C3	SVU23	THU22	57682	
1	BPO29C	G06H00A	BJA216	ASP2	57682 522196	
1	BPO35C	G06H00A	BJA216	ASP2	57683 522196	
1	BPO38B	F08H00A	BJA219	ASP1	57683 522196	
1	BPO39B	F08H00A	BJA219	ASP1	57682 522196	
1	BPO43C	G96H00A	BJA216	ASP2	500820 522196	
1	BPO44B	F08H00A	BJA219	ASP1	500820 522196	
1	BPZ42	F08H00A	BJA219	ASP1	500817 522196	
1	BPZ43	G06H00A	BJA216	ASP2	500817 522196	
2	BPG4	F10H00 F12H00	SHF10 SHF12	THF10 CCWP1	500669 500674	2
2	BPG5	G10H00 G12H00	SHG10 SHG12	THG10 CCWP2	500669 500674	2
2	BPG6	H10H00 H12H00	SHH10 SHH12	THH10 CCWP3	500669 500674	2
2	BPO3	H10H00 H12H00	SHH10 SHH12	THH10 CCWP3	500606	1

Table 3.12.2-2 Pullboxes Containing In-scope Medium Voltage Cable						
Unit	**Pullbox**	**Cable ID**	**From**	**To**	**Dwg**	**Note**
2	BPO6	G10H00 G12H00	SHG10 SHG12	THG10 CCWP2	500606	1
2	BPO8	F10H00 F12H00	SHF10 SHF12	THF10 CCWP1	500606	1
2	BPO13	TUV200A1 TUV200A2 TUV200A3 TUV200B1 TUV200B2 TUV200B3 TUV200C1 TUV200C2 TUV200C3	SVU23	THU22	500608	
2	BPO16	G06H00A	BJA226	ASP2	500608 522196	
2	BPO19	F08H00A	BJA218	ASP1	500608 522196	
2	BPO25	TUV200A1 TUV200A2 TUV200A3 TUV200B1 TUV200B2 TUV200B3 TUV200C1 TUV200C2 TUV200C3	SVU23	THU22	500609	
2	BPO33	F08H00A	BJA218	ASP1	500614 522196	
2	BPO33A	G06H00A	BJA226	ASP2	500614 522196	
2	BPO43B	G06H00A	BJA226	ASP2	500820 522196	
2	BPO43C	F08H00A	BJA218	ASP1	500820 522196	
2	BPZ42	F08H00A	BJA218	ASP1	500692 522196	
2	BPZ43	G06H00A	BJA226	ASP2	500692 522196	

NOTE: 1. Pullbox is located indoors and cannot fill with water (LRFS-09-001).
2. Pullbox is located indoors and has a drain to the Aux Building sump.

4.0 METAL ENCLOSED BUS

4.1 Methodology

Electrical metal enclosed bus is an enclosed bus that is not part of an active component such as switchgear, load centers, or motor control centers. There are typically three types of metal enclosed bus.

- Segregated Phase Bus
- Isolated Phase Bus
- Non-Segregated Phase Bus

A review of DCPP electrical design was performed to determine the types of metal enclosed bus used. Each bus was then evaluated to determine if it performs an intended function that meets the criteria of 10 CFR54.4.

4.2 Metal Enclosed Bus Summary

DCPP uses Isolated Phase Bus (Iso-Phase Bus) to backfeed power from the main transformers to Unit Auxiliary Transformers as a secondary source of station blackout recovery. (Ref. TR-2DC)

DCPP uses non-segregated phase metal enclosed bus (MEB) to supply power to the startup and vital busses from the plant transformers.

DCPP does not use segregated phase bus.

4.3 In-scope Metal Enclosed Bus

The in-scope Iso-Phase Buses are those in Units 1 and 2 that distribute power from the main transformer banks 1 and 2 to the primary side of the Unit Auxiliary Transformers.

The in-scope non-segregated buses are those required to support station blackout and recovery, as described in TR-2DC.

The in-scope metal enclosed buses are shown in Table 4.3.

Table 4.3 in-Scope Metal Enclosed Bus

Unit	From	To	Type
1	Main Trans Bank 1	UAT12	Iso-Phase
1	UAT12X	SHF13, SHG13, SHH13	Non-seg
1	SUT11	SVU12	Non-seg
1	SVU14	SUT12	Non-seg
1	SUT12X	SHG15	Non-seg
1	SHG15	SHF14, SHG14, SHH14	Non-seg
2	Main Trans Bank 2	UAT22	Iso-Phase
2	SUT21	SVU24	Non-seg
2	UAT22X	SHF13, SHG13, SHH13	Non-seg
2	SUT22X	SHG15	Non-seg
2	SHG15	SHF14, SHG14, SHH14	Non-seg
2	SU Bus at SVU25	SVU11	Non-seg

Table 4.3 in-Scope Metal Enclosed Bus			
Unit	From	To	Type
2	Non-seg from 12KV cable at SUT22	SUT22	Non-seg

5.0 FUSE HOLDERS

5.1 Methodology

The Fuse Holders aging management program applies to fuse holders located outside of active devices and that perform a license renewal intended function. The program focuses on the metallic clamp portion of the fuse holder. The aging effects of interest are either thermal fatigue caused by ohmic heating, thermal cycling, or electrical transients, or mechanical fatigue caused by frequent removal/replacement of the fuse or vibration, chemical contamination, corrosion, and oxidation.

A review of the DCPP Fuse List resulted in identification of fuses that are not enclosed inside active devices (e.g., switchgear, power supplies, battery chargers, or circuit boards).

Each fuse box was then evaluated to determine whether any of the fuses within the box perform a license renewal intended function.

It is assumed all fuses are subject to thermal fatigue effects. An additional review was performed to determine whether any of the in-scope fuse holders are subject to regular removal for testing, maintenance or operations. Those fuse holders are subject to additional mechanical fatigue aging effects.

5.2 Fuse Block Aging Effects

Metallic components of fuse holders are subject to aging stressors from fatigue, mechanical stress, vibration, chemical contamination, and corrosion. This program focuses on the metallic clamp portion of the fuse holders and monitors for thermal or mechanical fatigue.

Thermal fatigue will be evident in the form of high resistance caused by ohmic heating, thermal cycling or electrical transients. Mechanical fatigue will also be evident in the form of high resistance caused by frequent removal/replacement of the fuse or vibration, chemical contamination, corrosion or oxidation of the metallic components. No fuses within the scope of license renewal at DCPP are frequently removed or replaced.

High resistance will be evident by the loosening of connections over time. This loosening of components will be evident in the temperature of the contact surfaces being elevated above surrounding or similar connections in the vicinity. Testing by thermography will identify loosening metallic components by identifying elevated temperatures at the point of loosening.

5.3 Fuse Holder Scoping

Table 5.3-1 lists all fuse boxes not located inside active devices. The following DCPP stand alone fuse boxes were evaluated:

Table 5.3-1 Stand Alone Fuse Boxes

Unit	Panel	Schematic	Conn Dwg	Description	Scope	Note
1	BTD311	338209	663086-104	Main Cardox Panel	Y	
1	EDFBN15	455065	445277	Bolted-in battery fuses	Y	1
1	EDFBN16	455065	445277	Bolted-in battery fuses	Y	1
2	BTH115		441547	Annunciator Terminal Box	Y	
2	EDFBN25	445295	445296	Bolted-in battery fuses	Y	1
2	EDFBN26	445295	445296	Bolted-in battery fuses	Y	1
1	BJH106	663228-1	444320	Rod control power supply	N	
1	BTC300	437554	437760	Feedwater Heater Controls	N	
1	BTD304	437561	477758	Main Steam Reheater Drains	N	
1	EJ31R09	216152	437902	Personal Hatch (lighting)	N	
1	EJ41R06	216152	437903	Personal Emergency Hatch	N	
1	EJFBUPS2		437901	Lighting	N	
1	EL34R07		437902	Equipment Hatch	N	
1	EL53R17		437904	Equipment Hatch	N	
1	EPDT103	4038905	52238	Security Fuse Panel	N	
1	EPFB43A	494432	502131	Spare	N	
1	EPFB43B	494432	502131	Spare	N	
1	EPFB44B	494432	502131	Spare	N	
1	EPFB44C	494432	502131	Spare	N	
1	PHT		437743	Temporary Plant Equipment	N	
1	PJUL1A		508181	Security Fuse Panel	N	
2	BJH106	663228-1	45782	Rod Control Power Supply	N	
2	BTB525	108034-15D	441373	Main Generator Aux Equip.	N	
2	BTC300	441257	441690	Feedwater Heater Controls	N	
2	BTD302	441279	441691	Main Steam Reheater Drains	N	
2	BTH102	452750	663228-1	Rod Control System	N	
2	BTH103	441506	441459	Rod Control Panel	N	
2	EJ31R09	219925	441493	Personal Hatch (Lighting)	N	
2	EJ41R06	219925	441494	Personal Emergency Hatch	N	
2	EJFBUPS2	441492		Lighting	N	
2	EL34R11		441493	Emergency Hatch	N	
2	EL53R17		441495	Emergency Hatch	N	
2	EPFB45A	494432	502131	Spare	N	
2	EPFB45B	494432	502131	Spare	N	
2	EPFB46B	494432	502131	Spare	N	
2	EPFB46C	494432	502131	Spare	N	
2	MP2M12	663005-8		Crane and Trolley	N	

NOTE 1 – Bolted in fuses, aging management not required

5.4 Fuses Routinely Pulled

The fuses within the scope of license renewal at DCPP are not frequently removed or replaced.

6.0 CABLE CONNECTIONS

6.1 Methodology

All cable and connections in the plant are within the scope of the Cable Connections aging management program. “Cable” includes all power, instrument, and control cables. “Connections” includes connectors, splices, fuse holders, and terminal blocks

6.2 Cable Connection Inspection Sample Selection

The Electrical Cable Connections aging management program is a sampling program and requires that the technical basis for the sample selection be documented. NUREG-1801 aging management program XI.E6 “Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements” requires that the factors to be considered for sampling are: application (high, medium and low voltage), circuit loading, and location (high temperature, high humidity, vibration, etc.). LR-ISG-2007-02 modifies the description of factors to be considered to: voltage level (medium and low voltage), circuit loading (high loading), and location (high temperature, high humidity, vibration, etc.).

6.2.1 Voltage

Medium voltage is defined in the XI.E3 aging management plan as 2 kV to 35 kV. Therefore voltage levels below 35 KV should be addressed. At DCPP those voltage levels are:

- 12 kV AC
- 4.16 kV AC
- 480 VAC
- 120VAC
- 125VDC

6.2.2 Circuit Loading

Significant voltage exposure is defined in XI.E3 as “subjected to system voltage more than twenty-five percent of the time.” Therefore equipment in the selected sample at each of the voltage levels should be energized at least twenty-five percent of the time.

6.2.3 Temperature and Humidity

DCM T-20 Table A4.2-1 identifies the normal temperature and humidity environments in various spaces at Diablo Canyon. Cable connections included in the sample should be representative of locations within the various spaces normally in the upper half of the temperature and/or humidity ranges as shown in DCM T-20.

In general, the sample shall contain cable connections at devices in the following temperature and/or humidity environments

- Inside Containment, > 85°F and/or >60% RH
- Outside Containment, >75°F and/or >55% RH

6.2.4 Vibration

Experienced plant operating, maintenance and engineering personnel shall be involved in identifying those components experiencing high vibration during normal operation. The sample shall include cable connections at devices representative of the vibration levels identified.

6.2.5 Equipment

Table 6.2.5 lists component types that are representative of the electrical devices to which cable connections may be attached. The scope of the Electrical Cable Connections aging management program includes the field side of the termination of cables at these types of components.

Table 6.2.5 Component Types

Component Type	Voltage Rating
Transformers	Any
Switchgear	12 kV
Switchgear	4.16 kV
Load Center/MCCs	480 VAC
Distribution Panels	120 VAC, 125 VDC
Batteries	125 VDC
Motors	Any
UPS	Any
Control Panel Power Supply	120 VAC, 125 VDC
Motor Operated Valve	Any
Solenoid Operated Valve	Any

7.0 CABLE TIE WRAP

7.1 Methodology

The DCPP CLB and design documents were reviewed to determine that cable tie wraps perform no license renewal functions and failure of cable tie wraps would not prevent any safety related equipment from performing its intended functions. DCPP has no current licensing basis (CLB) requirements that cable tie wraps remain functional during and following design-basis events. Tie wraps are not credited at DCPP for seismic qualification of the cable tray support system or any other plant equipment. Therefore, aging management of cable tie wraps is not required.

7.2 Evaluation of Cable Tie Wrap Aging Effects

Cable tie wraps can experience fatigue due to heat and radiation.

DCPP uses nylon tie wraps that are resistant to heat related aging. Nylon has a 60 year service environment of 119°F. Most areas at DCPP have a maximum operating temperature of 104°F; a few rooms have a maximum temperature of 122°F.

DCPP uses radiation resistant fluoropolymer (Tefzel) tie wraps in containment areas, on the current reactor head, and above the refueling pool. Tefzel has a 60 year service environment of 228°F and 3 x 10^7 rads. The normal operating temperature for containment is 120°F with a 60 year normal dose of 1.5 x 10^7 rads.

7.3 (a)(2) Evaluation of Cable Tie Wraps

Cable tie-wraps do not perform license renewal functions and the failure of the tie-wraps would not prevent any safety related equipment from performing its intended functions. DCPP has no current license basis (CLB) requirements that cable tie-wraps remain functional during or following design events.

The AD4 series of procedures restrict the type of tie-wraps allowed inside of containment. Tie-wraps with metal clips are not approved for use in containment or in Foreign Material Exclusion (FME) areas. The impact of loose tie-wraps in the Residual Heat Removal (RHR) system and Containment sump has been evaluated.

Nylon tie-wraps have been evaluated for use and are allowed in most locations. They are used to provide organizational and housekeeping functions. The specific locations or placement of tie-wraps are not controlled or documented. They are used for various applications within a power plant to secure all types of equipment such as tags, signage, barriers, and to lock wire manual valves.

DCPP operating experience indicates that tie-wraps installed in the general plant areas and enclosures do not pose a hazard. Good housekeeping and FME practices prevent tie-wrap related failures that could prevent satisfactory accomplishment of the applicable functions of the SSCs identified under 10 CFR 55.4(a)(1). Therefore, tie-wraps are not subject to aging management review for the following reasons:

- Tie wraps are lightweight and nonconductive
- Sensitive components that could be impacted by a loose tie wrap are installed within protective enclosures.
- DCPP has experienced no equipment failures due to tie wrap failures.
- DCPP employs good housekeeping and FME practices.
- Impacts of loose tie-wraps, in containment, have been evaluated.

8.0 SWITCHYARD

8.1 Methodology

Components of the DCPP Switchyard required to support Station Blackout Recovery are within the scope of license renewal. The components are high voltage insulators, transmission conductors and connectors, and switchyard bus and connections.

Switchyard transmission and conductor management conforms to State of California General Order 95 to ensure public safety and reliability. The program is enhanced to identify aging effects required for license renewal.

The technical information and guidance in EPRI 1001997 has been considered in determining the aging effects requiring management.

8.2 Switchyard Boundary

8.2.1 230 kV Switchyard

Transmission conductors and connections, their supporting horizontal and vertical porcelain high voltage insulators, and switchyard bus and connections from disconnects 217 and 219 to Standby Startup Transformers 11 and 21 are within the scope of license renewal.

8.2.2 500 kV Switchyard

Transmission conductors and connections, their supporting horizontal and vertical high voltage insulators, and switchyard bus and connections from circuit breakers 532/632 (Unit 1) and 542/642 (Unit 2) to the respective unit main transformers are within the scope of license renewal.

8.3 Switchyard Aging Effects Requiring Management

8.3.1 Contamination, corrosion, and wear of high voltage insulators will be managed.

8.3.2 Aluminum buses are susceptible to corrosion buildup or cracks at joints and connections.

8.3.3 Connections are susceptible to degrading connections in affected or parallel conductors.

8.3.4 Conductors and their supports are susceptible to broken strands and wear at connections and support points.

9.0 REFERENCES

9.1 Industry References

9.1.1 EPRI TR1013475, February 2007, “Plant Support Engineering: License Renewal Electrical Handbook, Revision 1 to EPRI Report 1003057.”

9.1.2 SAND96-0344, Sept. 1966, "Aging Management Guideline For Commercial Nuclear Power Plants – Electrical Cable and Terminations"

9.1.3 NUREG/CR-6384, Vol. 1, April 1996, "Literature Review of Environmental Qualification of Safety-Related Electric Cables.

9.1.4 Tyco Catalog 1654025, December 2003, "High Performance Wire and Cable Spec 44."

9.1.5 LR-ISG-2007-02, "Final License Renewal Interim Staff Guidance: Changes to Generic Aging Lessons Learned (GALL) Report Aging Management Program (AMP) XI.E6, Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements."

9.2 DCPP Licensing Basis

9.2.1 DCPP UFSAR 2.3.1.2, Rev. 17, "General Climate."

9.2.2 DCPP UFSAR 2.3.2.2.1, Rev. 17, "Wind Speed and Wind Direction."

9.2.3 DCPP UFSAR 8.3.1.4.3.1, Rev. 17, "Construction and Voltage Ratings."

9.2.4 DCPP UFSAR Appendix 8.3B, Rev. 17, "Insulated Cable Construction and Voltage Ratings."

9.2.5 DCM T-20, Appendix A, Rev 10, "Environmental Qualification."

9.2.6 EQ File EH09, Rev. 10, "BIW Fan Cooler Cables."

9.2.7 EZ-002, Rev. 5, "Environmental Qualification (EQ) Requirements: Bases for 'Note 11' and 'Note 16' Devices; Bases for the 'Required Post-DBA Operating Time' and 'Minimum Required Qualification time;' Review of Potential 10CFR50.49(b)(2) Devices; and Radiation EQ of Non-Electronic Devices subject to a TID of between 10^3 and 10^4 Rads."

9.3 DCPP Documents

9.3.1 DCPP Ltr LRFS-08-162, September 17, 2008, High Voltage Components

9.3.2 DCPP Ltr LRFS-08-164, September 17, 2008, In Scope High Voltage Circuits

9.3.3 DCPP Ltr LRFS-08-165, September 17, 2008, Electrical Penetrations

9.3.4 DCPP Ltr LRFS-08-166, September 23, 2008, Radiation Monitors 25 and 26

9.3.5 DCPP Ltr LRFS-08-172, October 8, 2008, Medium Voltage Cables in Scope

9.3.6 DCPP Ltr LRFS-08-175, October 21, 2008, Medium Voltage Wrapup

9.3.7 DCPP Ltr LRFS-08-180, November 20, 2008, NE-31, NE-32, R-58 and R-59

9.3.8 DCPP Ltr LRFS-08-181, December 3, 2008, Stand-alone Fuse Boxes

9.3.9 DCPP Ltr LRFS-09-001, January 14, 2009, BPOxx Pull Boxes

9.3.10 DCPP Ltr LRFS-09-002, January 14, 2009, Unit 2 Load Centers

9.3.11 DCPP Scoping Paper, March 23, 2009, Diablo Canyon Tie Wrap License Renewal Scoping Paper

9.4 DCPP Procedures

9.4.1 DCPP MP E-63.3D, Rev. 2, “4 & 12 kV Switchgear Bus Connection Resistance.”

9.4.2 STP I-39-R44A.B, Rev. 11, “Containment Ventilation Exhaust RM-44A Radiation Monitor Calibration.”

9.4.3 STP I-39-R44B.B, Rev. 11, “Containment Ventilation Exhaust RM-44B Radiation Monitor Calibration.”

9.4.4 STP I-118B2, Rev. 5B, “Control Room Pressurization Radiation Monitor Isotopic Calibration RM-51/52/53/54”

9.4.5 STP I-119B3, Rev. 5, “Rad Source Presentation (ISO) CAL Fuel Hdlg Bldg Area.”

9.5 Communication Drawings (XI.E1)

9.5.1 033443, sh. 1, Rev 14, Telephone Cable and Wire Specifications

9.5.2 033443, sh. 2, Rev 14, Telephone Cable and Wire Specifications

9.5.3 033443, sh. 3, Rev 13, Telephone Cable and Wire Specifications

9.5.4 469992, Rev 7, Elementary Diagram for Communications Equipment Inside Plant Radio System Diablo Canyon Power Plant

9.6 NI Drawings (XI.E2)

9.6.1 437888, Rev 9, “Diagram of Connections Reactor Incore & NIS Detectors, Unit 1”

9.6.2 437940, Rev 16, “Diagram of Connections Penetrations No. 6E, 10E, 20E & 25E, Unit 1”

9.6.3 437974, Rev 13, “Diagram of Connections NIS Rack A, Unit 1”

9.6.4 437975, Rev 14, “Diagram of Connections NIS Rack B, Unit 1”

9.6.5 437976, Rev 14, “Diagram of Connections NIS Rack C, Unit 1”

9.6.6 437977, Rev 11, “Diagram of Connections NIS Rack D, Unit 1”

9.6.7 441465, Rev 14, "Diagram of Connections Penetration No. 6E, 10E, 20E & 25E, Unit 2"

9.6.8 448917, Rev 18, "Diagram of Connections Control Console Section ICC1, Unit 1"

9.6.9 452742, Rev 10, "Diagram of Connections Reactor Incore & NIS Detectors, Unit 2"

9.6.10 452743, Rev 13, "Diagram of Connections NIS Rack A, Unit 2"

9.6.11 452744, Rev 12, "Diagram of Connections NIS Rack B, Unit 2"

9.6.12 452745, Rev 10, "Diagram of Connections NIS Rack C, Unit 2"

9.6.13 452746, Rev 10, "Diagram of Connections NIS Rack D, Unit 2"

9.6.14 502127, Rev 30, "Diagram of Connections Elev Below 140'-0" Area GE & GW

9.7 RM Drawings (XI.E2)

9.7.1 447528, Rev 12, "Diagram of Connections Control Room Ventilation Chlorine & Radiation Monitor Rack"

9.7.2 501163, Rev 10, "Diagram of Connections Ventilation Equipment Turbine Building Area "A" Elev 140'-0", Unit 1"

9.7.3 501164, Rev 11, "Diagram of Connections Ventilation Equipment Turbine Building Area "A" Elev 140'-0", Unit 1"

9.7.4 501170, Rev 8, "Diagram of Connections Ventilation Equipment Turbine Building Area "A" Elev 140'-0", Unit 2"

9.7.5 501171, Rev 8, "Diagram of Connections Ventilation Equipment Turbine Building Area "A" Elev 140'-0", Unit 2"

9.7.6 521663, Rev 2, "Diagram of Connections Elev 85'-0" to 140'-0" Areas J & L, Unit 1"

9.7.7 521671, Rev 1, "Diagram of Connections Elev 85'-0" to 140'-0" Areas J & L, Unit 2"

9.7.8 06011481-28, Rev C, "Connection Diagram Containment Purge Exhaust – RMS Detector"

9.7.9 06011481-61, Rev E, "Customer Connections Containment Purge Exhaust – RMS"

9.8 MV Cable (XI.E3) & MEB (XI.E4)

9.8.1 437529, Rev 39, "Single Line Meter & Relay Diagram Generation Excitation Main & Auxiliary Transformers"

9.8.2 437530, Rev 36, "Single Line Meter & Relay Diagram 12KV Start-up System"

9.8.3 437531, Rev 27, "Single Line Meter & Relay Diagram 12KV System"

9.8.4 437532, Rev 27, “Single Line Meter & Relay Diagram 4160 Volt System”

9.8.5 437533, Rev 36, “Single Line Meter & Relay Diagram 4160 Volt System”

9.8.6 441226, Rev 28, “Single Line Meter & Relay Diagram Generator Excitation Main and Auxiliary Transformers”

9.8.7 441227, Rev 21, “Single Line Meter & Relay Diagram12KV System Bus Section ‘D’ & ‘E’, Unit 2”

9.8.8 441228, Rev 16, “Single Line Meter & Relay Diagram 4160V System Bus Section ‘D’ & ‘E’, Unit 2”

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9.8.10 441230, Rev 23, “Single Line Meter & Relay Diagram 4160V System Bus Section ‘G’ & ‘H’, Unit 2”

9.9 Pullboxes (XI.E3)

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9.9.2 57568, Rev 59, “Cable Tray and Conduit Layout Plan Below Elev 107’-0” Area ‘A’”

9.9.3 57597, Rev 12, “Embedded Conduit Layout El 85’-0” Areas ‘FW’-‘GW’”

9.9.4 57658, Rev 12, “Conduit Layout Outdoors Area 1”

9.9.5 57660, Rev 21, “Conduit Layout Outdoors Area 3”

9.9.6 57682, Rev 21, “General Arrangement of Electrical Pull Boxes and Duct Runs”

9.9.7 57683, Rev 16, “General Arrangement of Electrical Pull Boxes and Duct Runs”

9.9.8 500606, Rev 10, “Conduit Layout Outdoors Area 1”

9.9.9 500608, Rev 7, “Conduit Layout Outdoors Area 3”

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9.9.11 500614, Rev 16, “Electrical Pull Boxes & Duct Runs”

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9.9.14 500674, Rev 5, “Embedded Conduit Layout Elevation 85’-0” Area ‘H’ & ‘K’”

9.9.15 500692, Rev 12, "Electrical Conduit and Lighting Layout Intake Structure – Plan Elev +5' – 0""

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9.10.2 437901, Rev 89, "Electrical Diagram and Panel Schedule Lighting Distribution PL12-1 thru 12-5, PJ12-1, PJ12-2, & PLD-12"

9.10.3 437902, Rev 63, "Electrical Diagram & Panel Schedule Lighting Distribution"

9.10.4 437903, Rev 40, "Electrical Diagram & Panel Schedule Lighting Distribution Panels PL14-1, PD14, & PJ14-1"

9.10.5 437904, Rev 46, "Electrical Diagram & Panel Schedule Lighting Distribution"

9.10.6 441493, Rev 59, "Electrical Diagram & Panel Schedule Lighting Distribution"

9.10.7 441495, Rev 35, "Electrical Diagram and Panel Schedule Lighting Distribution"

9.10.8 445277, Rev 5, "Diagram of Connections 125 Volt Battery No 15 and 16

9.10.9 502131, Rev 42, "Diagram of Connections Elev 100'-0", 115'-0", 128'-0" & 140'-0" Area H"

9.11 Switchyard

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9.11.2 036687, Rev 18, "Bill of Materials for Arrangement of 500KV Switch, Bus & HVCB Structure"

9.11.3 036706, Rev 3, "Bill of Materials for Arrangement of 230KV Switch, Bus & HVCB Structure"

9.11.4 050040, Rev 4, "Bill of Material to Accompany Dwg 500804 & 500805 Arrangement of Standby Start-up Transformers No. 11, 12, & 21"

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9.11.9 217852, Rev 9, “Unit No. 1 Tie Switchyard 500KV Tower Line”

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9.11.11 328934, Rev 8, “230KV & 500KV Lines Power Plant to Switch-yard”

9.11.12 435897, sh. 3, Rev 3, “Arrangement of 230KV Switch, Bus & Circuit Breaker Structures”

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